System Reliability Assurance Study

conEdison

Prepared by

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Executive Summary

The electric rate plan approved by the Public Service Commission (PSC) in Case 04-E-0572 included a provision for Consolidated Edison Company of New York, Inc. ("Con Edison" or the "Company") to develop a System Reliability Assurance Study (SRAS).

The purpose of the SRAS is twofold:

- Assess the potential for the New York City locational capacity requirement (LCR) to change over the 10-year period, 2006 through 2015; and
- Preliminarily examine the supply and demand side resource options that may be needed to meet system demand, particularly in New York City ("the City"), over this same period.

The LCR is the minimum amount of generation capacity that is required to be electrically located within the City to ensure the reliability of the City's bulk power system. This requirement is a result of transmission constraints that limit the import of power into the City from rest of New York State ("the State") and New Jersey. The LCR is determined annually by the New York Independent System Operator (NYISO) and is currently set at 80% of the City's forecasted electric peak load.

Independently, but coincident with the SRAS, the NYISO has engaged in a Comprehensive Reliability Planning Process (CRPP) in order to develop a Reliability Needs Assessment (RNA) for New York State. The RNA covers the same 10-year period as the SRAS and focuses on assessing when new capacity will be needed in New York State and what the magnitude of the need will be (i.e., how many megawatts).

In accordance with the Company's electric rate plan, the SRAS was conducted in coordination with the NYISO's CRPP. In addition to coordinating the work with NYISO, Con Edison also utilized a collaborative process in developing the SRAS. Input was solicited from the Collaborative (who were also parties to the Company's electric rate agreement) during and after periodic status review meetings. Early on in the process, the Collaborative agreed that the SRAS would focus on resource adequacy and assume that any voltage compensatory needs would be addressed between the pertinent transmission owner(s) and the NYISO through the NYISO's CRPP.

Comparison of NYISO RNA and Con Edison SRAS

The NYISO RNA examined the effect of transmission limitations on resource needs by using three different sets of transmission transfer limits:

- Free-flowing, which assumes no transmission limitation within the State
- Thermally constrained transmission limits only, which assumes any voltage concerns would have already been addressed
- The most limiting transmission thermal or voltage constraint

Because the SRAS focused on resource adequacy and not on voltage limitations, the comparable NYISO RNA case for comparison with the SRAS would be the RNA case using thermally constrained transmission limits only. Significantly, studies performed by the New York State Reliability Council (NYSRC) Installed Capacity Subcommittee (ICS) noted that the voltage constrained transmission limits modeled as year round limits in the NYISO RNA should be modeled as dynamic interface limits that are a function of load and the availability of generating units. Further, ICS found that use of the dynamic interface limits is essentially comparable to using thermally constrained transmission limits only.[1] Therefore, unless noted otherwise, discussion of the NYISO RNA through the rest of the SRAS report refers to the RNA case using thermally constrained transmission limits only.

Both the SRAS and the RNA used the General Electric (GE) Multi-Area Reliability Simulation (MARS) model to conduct the resource adequacy analysis.[2] While both the SRAS and the RNA used the MARS model, they made different assumptions for the following type of information in their respective MARS databases:

- Transmission topology, which describes how the electric transmission system is interconnected, and the transfer capability of the interfaces that connect the different parts of the system.
- Currently known and planned generation additions and retirements within the 10-year study horizon.
- Currently known and planned transmission additions within the 10-year study horizon.

Figure ES1 shows the differences in the assumptions regarding the planned additions and retirements between the Con Edison SRAS base case and the NYISO's RNA base case.

[1] For further information refer to the meeting minutes of the November 30, 2005 meeting of the Installed Capacity Subcommittee (ICS), which is available on the NYSRC web site (www.nysrc.org).

[2] The MARS model is an industry-accepted probabilistic reliability model. However, it does not model the transmission system in detail; for example, it cannot model phase angle regulator settings and position of shunt reactors.

Figure ES1. Differences Between NYISO RNA Base Case and Con Edison SRAS Base Case

			MW Capacity		
	Zone	**Date**	**Summer**	**Winter**	**Same as NYISO RNA Base Case?**
Generation Additions					
Con Edison – East River Repowering	J	Apr. 2005	288	288	Yes
NYPA – Poletti Expansion	J	Jan. 2006	500	500	Yes
SCS Energy – Astoria Energy	J	Apr. 2006	500	500	Yes
PSEG – Bethlehem	F	Jul. 2005	750	750	Yes
Calpine – Bethpage 3	K	May 2005	79.9	79.9	Yes
Pinelawn – Pinelawn Power 1	K	May 2005	79.9	79.9	Yes
Caithness Energy – Caithness, LI	K	May 2008	310	310	This capacity addition is not in the NYISO RNA
NYPA 500 MW Request For Proposal (RFP) - New In-City Unit	J	Jan. 2010 – date coincides with NYPA Poletti 1 retirement	500	500	This capacity addition is not in the NYISO RNA
Generation Retirements					
Con Edison – Waterside 6, 8, 9	J	May 2005	167.2	167.8	Yes
PSEG Power – Albany 1, 2, 3, 4	F	Feb.2005	312.3	364.6	Yes
NYPA – Poletti 1	J	Jan. 2010	885.3	885.7	NYISO RNA retires Poletti 1 in Feb. 2008
RGE – Russell Station	B	Dec. 2007	238	245	Yes
NRG – Huntley 63, 64	A	Nov. 2005	60.6	96.8	Yes
NRG – Huntley 65, 66	A	Nov. 2006	166.8	170	Yes
Mirant – Lovett 5	G	Jun. 2007	188.5	189.7	Yes
Mirant – Lovett 3, 4	G	Jun. 2008	242.5	244	Yes
Transmission Additions					
AE Neptune HVDC Line (PJM to Long Island)	PJM to K	Jun. 2007	660	660	Yes
Con Edison M29 Line (Sprain Brook to Sherman Creek)	I to J	Spring 2008	345 MW increase in transfer capability	345 MW increase in transfer capability	This transmission addition is not in the NYISO RNA base case[3]

[3] The NYISO conducted a sensitivity case that includes the M29 line.

The SRAS base case utilized the NYISO base case peak load forecast from the RNA.[4]

Figure ES2 provides a summary of comparison of the NYISO RNA and the SRAS.

Figure ES2. Comparison of RNA and SRAS

	NYISO RNA	SRAS
Reliability Assessment(s)	Resource Adequacy and Transmission Reliability	Resource Adequacy Only
Study Period	2006 - 2015	2006 - 2015
Base Case Assumptions	-	NYISO RNA plus Differences (Timing in Poletti Retirement, NYPA 500 MW RFP, M29 Feeder, Caithness Project)
Reliability Criterion Used to Determine Need Date in State	When Statewide LOLE > 0.1 day / year	When Statewide LOLE > 0.1 day / year
Criterion Used to Determine Where Resources Are Needed	Add 250 MW Combined Cycle Unit(s) to Load Zone with Highest LOLE and Repeat Until Statewide LOLE = 0.1 or Lower	Solve for New Resources Required for Statewide LOLE of 0.1; Then Solve for New Resources Required In Transmission Constrained Zones To Maintain the Statewide LOLE of 0.1
New York State Need	250 MW in 2009; 1,250 MW in 2010; rising to 2,250 MW in 2015 (Need in 2008 if voltage constrained limits are used)	430-770 MW in 2010, rising to 2,500 MW in 2015
Area with Greatest Need	New York City	Lower Hudson Valley to support export to New York City and Long Island (Increasing UPNY/SENY by 500 MW could defer New York State need date to 2011)
New York City Need	250 MW in 2009; 750 MW in 2010; rising to 1,500 MW in 2014 and 2015 (Also Recognizes Other Solutions May Exist)	118 MW in 2012, rising to 672 MW in 2015
Generic Analysis of Potential Resource Options	Not Conducted	Conducted Per Electric Rate Agreement

The difference between the SRAS and RNA regarding when new resources are needed is a result of more capacity assumed in the SRAS base case compared to the NYISO RNA base case. In both cases, when new resources are needed is

[4] Con Edison's internal base case peak load forecast for zone J (i.e., New York City) matches the NYISO base case peak load forecast through 2010, but over the 2011 to 2015 period the Con Edison forecast is about 30 MW higher on average than the NYISO forecast for zone J.

triggered by the retirement of the 885 MW Poletti 1 unit. In the SRAS, this occurs in 2010. In addition, the SRAS base case assumes a new 500 MW in-City unit (NYPA RFP) coming on line in 2010.

If the 500 MW NYPA RFP and the 310 MW Caithness plant were excluded from the SRAS, the generating capacity in the SRAS would be the same as in the RNA for years 2010 and beyond, and under this scenario, the SRAS would show a need in the State in 2010 of 1,580 MW at 18% statewide Installed Reserve Margin (IRM) requirement. However in 2010 but not beyond, there is enough locational capacity in New York City and Long Island to support a statewide IRM lower than 18% to meet the 0.1 day / year LOLE reliability criterion. Without the NYPA RFP and Caithness projects, lowering the IRM requirement from 18% to 17% in 2010 would reduce the 1,580 MW statewide need to 1,240 MW. Therefore, assuming the same level of generating capacity as in the RNA, the SRAS would show a need of at least 1,240 MW in the State in 2010, whereas the NYISO RNA showed a need of 1,250 MW. This demonstrates the different results between the RNA and the SRAS can be explained by the differences in the base case assumptions.

High Load Growth Sensitivity

The SRAS also evaluated a high load growth sensitivity case using the high load forecast from the NYISO RNA, which reflects a 1.5% compound annual growth rate (CAGR) in the State peak load compared to the base case CAGR of 1.2%. The results indicate that the year in which new resources are needed remains at 2010 for the State, and this need is triggered by the retirement of Poletti 1, as stated earlier. However, in the high-growth case, the need for additional capacity is greater.

Examination of Supply and Demand Side Resource Options for New York City

The SRAS identified a range of resource options to meet system reliability needs in New York City. The Collaborative determined that the options shown on Figure ES3 below best represent resources that are deemed to be technologically feasible for New York City within the time horizon of the study. While it is outside of the scope of the SRAS to address voltage requirements, it should be noted that out-of-City generation imported over transmission lines does not provide critical reactive power to the City to support load growth.

Figure ES3. Resource Options Considered in the Study

New Central Station Generation	Simple Cycle Gas Turbine (SCGT)
	Combined Cycle Gas Turbine (CCGT)
	Out-of-city SCGT with radial tie (SCGT + AC)
	Out-of-city CCGT with radial tie (CCGT + AC)
Re-powered Central Station Generation	Combined Cycle Gas Turbine (CCGT Repowering)
Transmission with Firm Generating Capacity	AC line with phase angle regulator to PJM (AC Line – PJM)
	AC line with phase angle regulator to Lower Hudson Valley (AC Line – LHV)
	High Voltage Direct Current line to PJM (HVDC – PJM)
	High Voltage Direct Current line to Lower Hudson Valley (HVDC – LHV)
Distributed Generation	Microturbine
	Microturbine Combined Heat and Power (CHP)
	IC Engine (natural gas fired)
	IC Engine CHP (natural gas fired)
	Molten Carbonate (MC) Fuel Cell
	Molten Carbonate (MC) Fuel Cell CHP
	Solar Photovoltaic (PV)
Demand Side Measures	Commercial HVAC
	Commercial Lighting
	Motors
	Residential HVAC
	Residential Lighting

A central station co-generation combined cycle plant can also improve system reliability, similar to a comparably electrically sized Combined Cycle Gas Turbine (CCGT) plant, by curtailing its steam production in favor of maximizing electrical output when needed. A co-generating plant can thus be treated as a variation of how a CCGT plant is operated. Therefore, the SRAS did not consider a central station co-generation combined cycle plant as a separate resource option for electric reliability.

For each of the resource options identified on Figure ES3 above, the SRAS conducted a cost-benefit analysis. The approach was to determine the net cost of each resource over its economic life per unit of "reliability benefit", i.e., a quantifiable measure of reliability improvement to New York's bulk power system and to New York City. Using this approach, cost-benefit ratios were calculated which quantify the net cost of capacity for each resource option to achieve the same level of reliability benefit derived from installing each option. The lower the cost-benefit ratio, the more cost-effective a resource option would be to provide the same level of reliability benefit.

In calculating costs and benefits, 250 MW and 500 MW blocks of each resource option were considered. The costs and benefits are defined as follows:

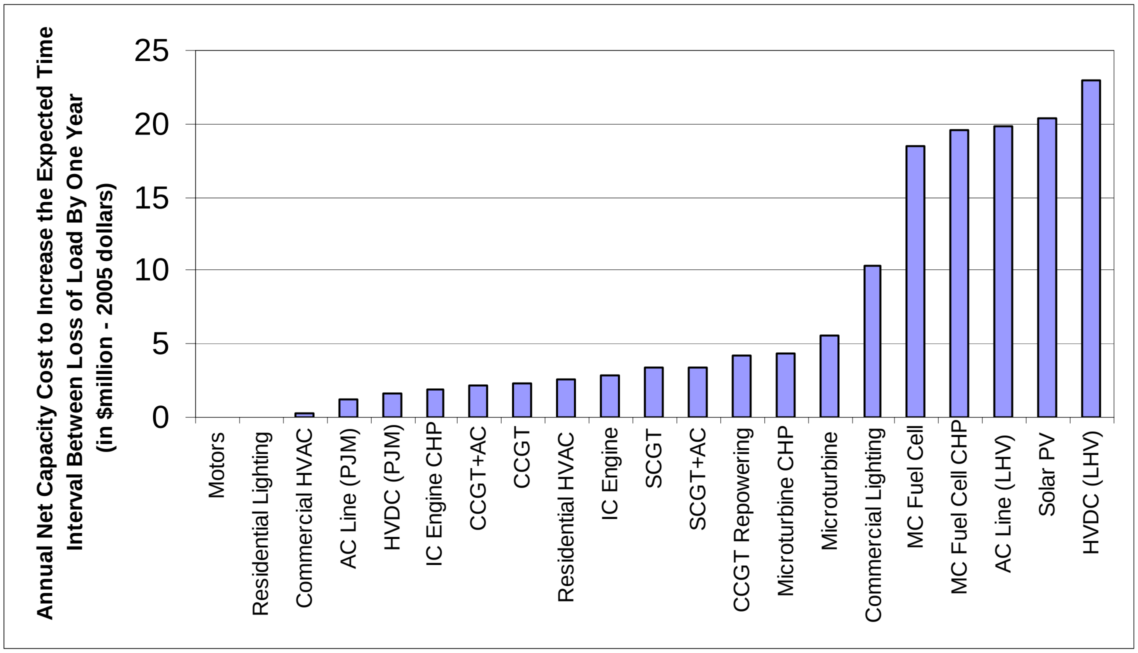
- Net cost of Capacity: Annualized capital and fixed O&M costs net of energy benefits (or energy savings, in the case of demand side measures)
- Reliability Benefit: Additional years gained in the expected time interval between loss-of-load events due to the installation of the resource option
- Cost-benefit ratios were calculated for the year 2010 (the year in which the SRAS identifies new resources are needed in the State)

The results, depicted on Figure ES4, show that transmission from the Lower Hudson Valley to New York City, i.e., the AC Line (LHV) and HVDC (LHV) options in Figure ES4, is not cost-effective. However, transmission from PJM with firm generating capacity[5], i.e., the AC Line (PJM) and the HVDC (PJM) options in Figure ES4, appears to be cost-effective. These two PJM transmission options reflect PJM's projected cost of new entry in New Jersey, because PJM-East itself will need new capacity by 2010. The PJM estimate of the cost of new entry in New Jersey may be optimistic[6]. Therefore, the cost-benefit ratios of the two transmission options shown on Figure ES4 may also be optimistic. In the final analysis, however, the attractiveness of any particular resource option will depend upon the responses received to an RFP.

Effective DSM energy efficiency options may be limited and may not yield load reduction levels comparable to new generation and transmission resources. In addition, the future incremental costs and benefits of energy efficiency measures will be altered by marketplace energy efficiency gains due to changes in consumer behavior and tighter energy efficiency standards that may be adopted. The SRAS analysis shows that, except for commercial lighting, DSM energy efficiency measures (i.e., the motors, commercial and residential HVAC and residential lighting options in Figure ES4) may be attractive without incentives and therefore should occur naturally. To the extent these DSM energy efficiency options should be occurring but are not, tighter energy efficiency standards and building codes would ensure the broadest, most cost-effective, most equitable and most permanent implementation of DSM.

[5] In order for generating capacity to be firm, the capacity must be owned or contracted for, but the capacity does not have to be from new generation.
[6] The PJM estimated cost of new entry in New Jersey is about $72/kW-yr, which is less than the NYISO estimated cost of new entry in the Albany area of $87/kW-yr. However, construction costs, (based on RS Means Construction Cost Index) in Northern New Jersey instead of being lower are about 15% higher than in the Albany area, which suggests that PJM may be understating the cost of new entry in New Jersey.

Figure ES4. Capacity Cost to Reliability Benefit Ratio of Resource Options

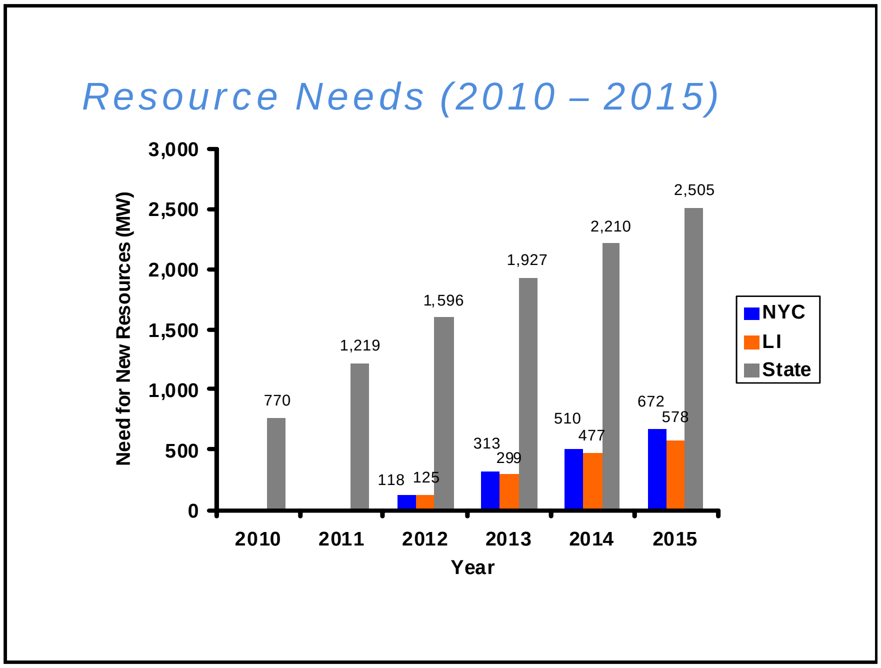


Conclusions and Recommendations

Figure ES5 shows that under the base case, 770 MW of new resources would be needed in the State by 2010, rising to about 2,500 MW by 2015. Figure ES5 also shows that New York City and Long Island would not need new resources until 2012. Furthermore, contributions from the 675 MW DSM Initiative adopted by the PSC in the last Con Edison electric rate case could defer the date by which New York City would need new resources even further, to possibly as late as 2014.

The SRAS also found that increasing the Upstate New York to South East New York (UPNY/SENY) interface by 500 MW would defer the need for additional new resources in the State by one year. However, adding a 500 MW HVDC line from the Lower Hudson Valley to New York City, without new generating capacity there, would have little reliability benefit, because there is insufficient generating capacity in the Lower Hudson Valley to support the additional export to New York City. On the other hand, adding 500 MW of new generating capacity in the Lower Hudson Valley without new transmission would achieve a reliability benefit for the State comparable to adding 500 MW of generating capacity in New York City. Over the 2006 – 2015 period, the Lower Hudson Valley is expected to see almost 1,200 MW load growth from 2005 level, which would require about 1,400 MW of capacity. As shown on Figure ES5, outside of New York City and Long Island, in 2015 new resources equal to 1,255 MW (i.e., 2,505 MW statewide less 672 MW New York City less 578 MW Long Island) would be required just to meet load growth in the Lower Hudson Valley. Placing new generation in the Lower Hudson Valley would not only meet load growth in that area, but also would provide critical reactive power in the Lower Hudson Valley and support transfer capability to New York City and Long Island.

Figure ES5. State, City and Long Island Resource Needs



The resource options analysis does not show any single resource option to be the solution to meet all resource needs. Identifying the needs and allowing the competitive market the opportunity to meet those needs is expected to result in a variety of solutions that would be more robust than a single backstop solution would provide. Con Edison has taken an active role in the development of the NYISO CRPP to foster competitive market opportunities for resource supplies and is optimistic that the NYISO planning process will lead to the development of proposed projects that will address resource needs. Both market solutions and backstop solutions will be proposed and evaluated within the framework of the NYISO CRPP.[7]

[7] The CRPP satisfies the requirement that SRAS make preliminary recommendations concerning the facilitation of the competitive development of generation, transmission and DSM.

1.0 Introduction

1.1 Purpose of Study

The electric rate plan approved by the Public Service Commission (PSC) in Case 04-E-0572 included a provision for Consolidated Edison Company of New York, Inc. ("Con Edison" or the "Company") to develop a System Reliability Assurance Study (SRAS). See Appendix A for this provision and the details of the study requirements. The purpose of the SRAS is to examine the supply and demand side resource options that may be needed to meet system demand, particularly in New York City ("the City"), over a 10-year period, 2006 through 2015, and to assess the potential for the minimum in-City locational capacity requirement (LCR) to change over this same period.[8]

1.2 Comprehensive Reliability Planning Process

In accordance with the requirements of the Company's electric rate plan, development of the SRAS was coordinated with the New York Independent System Operator's Comprehensive Reliability Planning Process (CRPP). In the CRPP, the New York Independent System Operator (NYISO) developed the Reliability Needs Assessment (RNA), which examines the same 10-year period as in the SRAS.

1.3 SRAS Collaborative Process

In conducting the SRAS, the Company used a collaborative process that sought input from the NYISO and the Collaborative, i.e., the parties to the Company's electric rate agreement, which included the New York State Department of Public Service (DPS), New York City Economic Development Corporation (NYCEDC), Independent Power Producers of New York (IPPNY), New York Energy Consumers Council (NYECC), Public Utility Law Project (PULP), Utilities Workers Union of America (UWUA) Local 1-2, New York State Consumer Protection Board (CPB) and the E Cubed Company, LLC. The Company met with the Collaborative four times: on March 11, 2005 to discuss the overall schedule and approach, on May 17, 2005 to review the base case assumptions of the SRAS, on August 5, 2005 to review the cost assumptions, and on October 20, 2005 to review the preliminary findings of the SRAS. In addition, the Collaborative was afforded the opportunity at these meetings to provide its input and comments on the materials presented by the Company at those meetings.

[8] Currently set at 80% of the forecasted in-City peak load by the New York Independent System Operator.

2.0 Study Methodology

2.1 Study Objectives

The study period of the SRAS is a 10-year period from 2006 through 2015. In accordance with the pertinent requirements in the Company's electric rate plan, the results required of the SRAS are as follows:

- Assess the potential for the minimum in-City LCR to change over time;
- Examine the supply and demand side resource options that may be needed to meet system demand, particularly in New York City;
- Give appropriate consideration to the cost-benefit and reliability impacts of each potential resource option;
- Include other considerations, such as adequacy of fuel supplies, desire for diversity of both fuel supplies and generation resources, Homeland Security needs and system security concerns, City land use limitations, and environmental and health issues; and
- Review and make preliminary recommendations concerning potential means of facilitating the competitive development of supply and demand side resource options needed for system reliability.

2.2 Reliability Modeling

2.2.1 General Electric Multi-Area Reliability Simulation Model

The General Electric (GE) Multi-Area Reliability Simulation (MARS) model was the analytical tool used for the reliability analysis in this study.[9] The MARS model is an industry-accepted reliability model, and is also utilized by the New York State Reliability Council (NYSRC) to determine the required statewide installed reserve margin (IRM) to meet the once in ten years loss of load expectation (LOLE) criterion. Input to the MARS model includes a detailed load, generation, and transmission representation of New York State ("the State"), as well as neighboring control areas. The MARS model calculates the standard reliability indices of daily and hourly LOLE (days/year and hours/year, respectively) and Loss of Energy Expectation ("LOEE" in MWh/year). The model also calculates the need for initiating Emergency Operating Procedures (EOPs), expressed in days/year. Examples of EOPs include special case resources (SCRs), emergency demand response programs (EDRPs), voltage reduction, reduction in operating reserves and public appeals.

A sequential Monte Carlo simulation forms the basis for the MARS modeling. The use of sequential Monte Carlo simulations allows for the calculation of time-correlated measures such as frequency

[9] The most recent MARS version at the time of the study (i.e., version 2.72) was used.

(outages/year) and duration (hours/outage). In assessing the reliability of an electrical grid, there are several types of randomly occurring events that must be taken into consideration in the Monte Carlo simulation, such as the forced outages of generating units and transmission feeders. The MARS model also captures the effect of deviations from the forecasted loads (which reflect normal weather) through the use of load forecast distribution profiles. It also models transmission import and export limitations between individual control areas.

A MARS simulation of one chronological year consists of thousands of iterations of the same year. In each iteration in MARS, the sequential Monte Carlo simulation steps through the year chronologically, recognizing that the status of electrical equipment in any given hour is not independent of its status in adjacent hours. Equipment forced outages are modeled by taking the equipment out of service for contiguous hours, with the length of the outage period being determined from the equipment's mean time to repair. Sequential Monte Carlo simulations can model events of concern that involve time correlations and can be used to calculate indices such as frequency and duration. The simulation is replicated for many times to create an artificial history that achieves an acceptable level of statistical convergence in the loss of load being calculated. The expected value in the loss of load, i.e., LOLE, is the average of all the replications of one simulated year.

2.2.2 **Resource Adequacy Criteria**

Although the focus of the SRAS is on New York City resource adequacy, the SRAS also needed to assess the resource adequacy of New York State because the resource adequacy criteria for New York City is a subset of the resource adequacy criteria for New York State and the two are interrelated.[10] The NYSRC establishes a statewide IRM requirement for the New York Control Area (NYCA) on an annual basis. Currently the IRM is 18% of the State's peak load in order to meet an LOLE criterion of no greater than once in ten years.[11] Based on the IRM set by the NYSRC, the

[10] A greater reserve margin in New York State as a whole can reduce the locational capacity requirement in New York City because more resources are available to serve the statewide load, which reduces the loss of load expectation in all areas.
[11] NYSRC Reliability Rule A-R1 (Statewide Installed Reserve Margin Requirements) states: "The NYSRC shall establish the IRM requirement for the NYCA such that the probability (or risk) of disconnecting any *firm load* due to *resource* deficiencies shall be, on average, not more than once in ten years. Compliance with this criterion shall be evaluated probabilistically, such that the loss of *load* expectation (LOLE) of disconnecting *firm load* due to *resource* deficiencies shall be, on average, no more than 0.1 day per year. This evaluation shall make due allowance for demand uncertainty, scheduled outages and deratings, forced outages and deratings, assistance

NYISO also establishes corresponding LCRs for New York City and Long Island, currently at 80% and 99% of the New York City and Long Island peak loads, respectively.[12]

The SRAS examines the resource adequacy of New York State by determining the NYCA LOLE for each study year, which is consistent with the approach used by the NYISO in its RNA. The year when new resources are needed in New York State is when the NYCA LOLE exceeds the 0.1 day per year criterion. In addition to determining NYCA LOLE, the SRAS was required to examine the in-City LCR over time. This was achieved by assuming that the current 18% IRM would remain constant over time. The SRAS also examined the impact of a lower IRM by determining the in-City LCR assuming the IRM is reduced to 17%.

For a description of the NYSRC procedure to determine the relationship between the NYCA IRM and the in-City LCR, see Appendix B.

2.2.3 **MARS Database Used In Resource Adequacy Modeling**

The resource adequacy modeling in both the SRAS and the NYISO's RNA was conducted using the GE MARS model. The MARS database used in the SRAS was developed from the proprietary MARS database the NYISO used in its RNA. Because GE is the only third party with access to the NYISO's proprietary MARS database, the Company, with the NYISO's permission, contracted GE to perform the resource adequacy modeling in MARS.[13] The resource adequacy modeling consists of the determination of LOLEs for each of the 10 years in the study period, as well as the in-City LCRs. For the SRAS, GE was instructed to use the NYISO's proprietary MARS database, but to update it with data provided by Con Edison where required to conform to the SRAS base case.

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over interconnections with neighboring *control areas*, *New York State Transmission System transfer capability*, and *capacity* and/or *load relief* from available *operating procedures*."

[12] NYSRC Reliability Rule A-R2 (Load Serving Entity (LSE) Installed Capacity Requirements) states: "*LSEs* shall be required to procure sufficient *resource capacity* for the entire *NYISO* defined *obligation procurement period* so as to meet the statewide *IRM* requirement determined from A-R1. Further, this *LSE capacity* obligation shall be distributed so as to meet *locational ICAP requirements*, considering the *availability* and capability of the *NYS Transmission System* to maintain A-R1 *reliability* requirements."

[13] Proprietary information in the NYISO MARS database includes generator and transmission forced outage rates, planned generating unit maintenances and the modeling of the neighboring control areas, such as the Pennsylvania-Jersey-Maryland (PJM) control area and the Independent System Operator of New England (ISO-NE) control area. The NYISO has non-disclosure agreements with PJM and ISO-NE to not release information of their systems that are in the NYISO MARS database.

2.2.4 **MARS Database Used In Reliability Impact Analysis**

In the resource options analysis phase of the SRAS, the Company also contracted with GE to conduct some of the MARS sensitivity cases to assess the reliability impact of the resource options. In addition, the Company used its own internal MARS database to supplement the reliability modeling of the resource options. The reliability impact of each resource option is determined by comparing the difference in output between two MARS simulations: one with the resource option and the other without the resource option. Before the Company's internal MARS database was used in the assessment of the reliability impact of the resource options, the internal MARS database was benchmarked against the NYISO's proprietary MARS database that GE used.

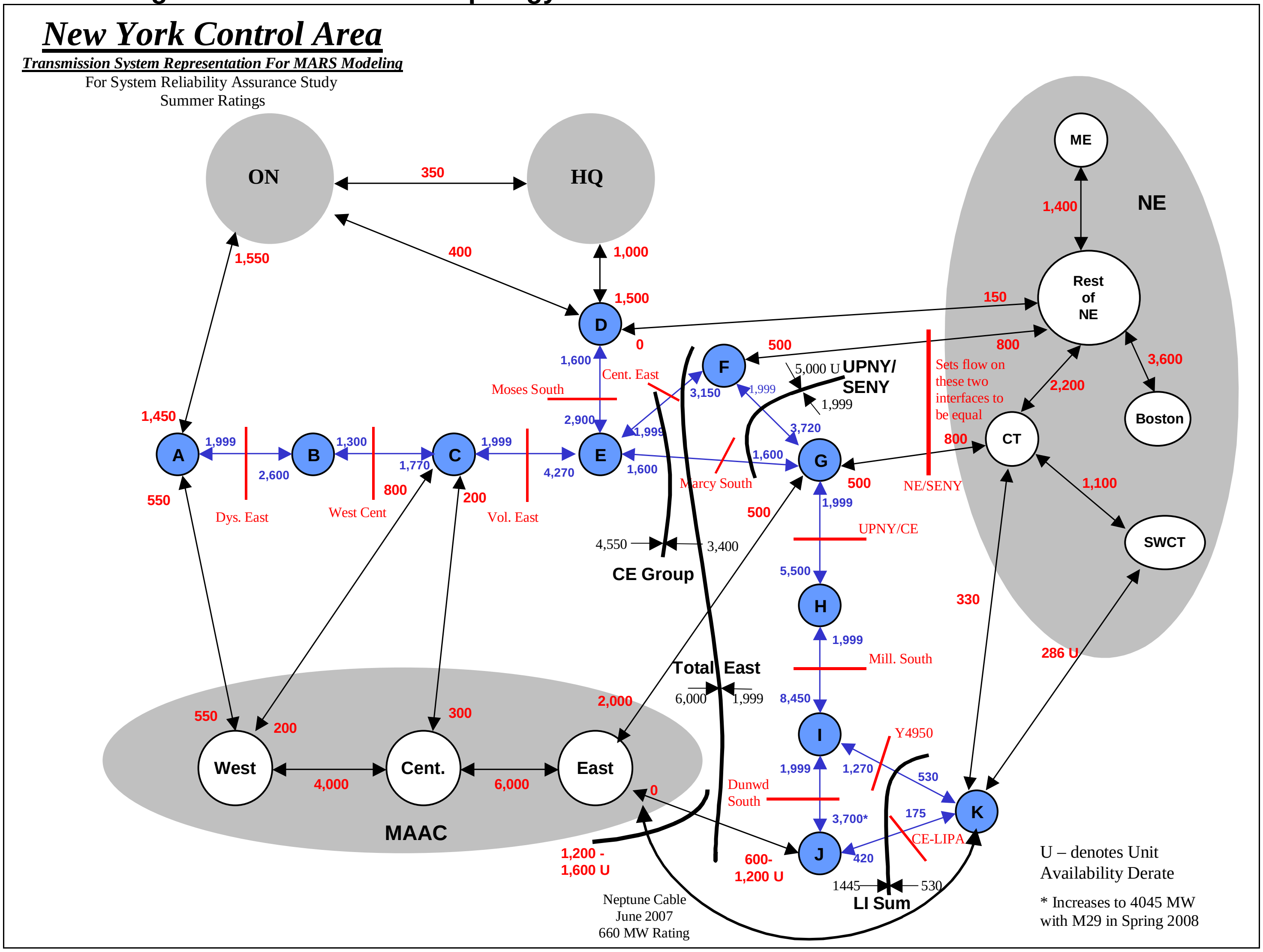
In the database benchmarking phase, the Company adjusted input parameters in the SRAS database that were edited out of the NYISO's MARS database, through an iterative process until the LOLE results approximated those provided by GE using the proprietary MARS database. For further discussion of the MARS database benchmarking, see Appendix C.

2.2.5 **Transmission Representation in MARS Database**

Figure 1 shows the transmission representation used in the SRAS MARS model. The representation is based on the transmission topology approved by the NYSRC Executive Committee at its August 12, 2005 meeting for use in the 2006 IRM Study.[14] This transmission topology uses thermally constrained limits only and is consistent with the objective of the SRAS to evaluate the resource adequacy needs, assuming any voltage compensatory needs would be addressed between the pertinent transmission owner and the NYISO through the NYISO's CRPP.

[14] Based on inputs from the NYISO staff, the NYSRC later included in the 2006 IRM Study the use of dynamic interface limits for the UPNY/CONED interface and the Dunwoodie South and Y49/50 interfaces to model voltage concerns raised in the NYISO RNA. The dynamic interface limits are a function of load and the availability of the 345 kV generating units in the Lower Hudson Valley and in New York City. The MARS simulations using the dynamic interface limits resulted in virtually no change to the New York City and Long Island LCRs at 18% statewide reserve margin when compared with the MARS simulations using thermal limits only. For further information refer to the meeting minutes of the November 30, 2005 meeting of the Installed Capacity Subcommittee (ICS), which is available on the NYSRC web site (www.nysrc.org).

Figure 1. Transmission Topology



2.3 Cost-Benefit Analysis

2.3.1 Resource Options Considered for the Study

The supply and demand resource options that were evaluated in the SRAS were selected through a collaborative effort and are listed in Section 5.1. The main categories of resource options are:

- In-City central station generation
- Out of City central station generation with radial tie
- Transmission with firm generating capacity
- Distributed generation (DG)
- Demand Side Management (DSM) energy efficiency measures

2.3.2 **Development of Cost and Performance Database**

The cost and performance data used in the resource options cost-benefit analysis were developed from publicly available sources that include industry reports and regulatory filings; subscription services such as Cambridge Energy Research Associates, Inc. (CERA) reports and SNL Financial reports; data from the New York State Energy Research and Development Authority (NYSERDA); news articles; and input provided from members of the Collaborative.

The cost data incorporates the costs of projects recently placed in service or currently under construction, as well as identifying an uncertainty band for each resource option to cover its probable cost spectrum. Appendix D lists the references used in this study.

The performance data includes full load heat rates for generation options, combined heat and power (CHP) efficiencies for DG resources, and gross and peak coincident load reduction characteristics for DSM energy efficiency measures.

2.3.3 **Equating Capacity Cost to Reliability Benefit**

The objective of the cost-benefit analysis is to compare viable resource options for New York City on a cost per "unit of reliability" basis. The benefit quantified is a *reliability* (as opposed to economic) benefit and can be expressed as either the improvement in loss of load expectation, or reduction in unserved energy[15] with the addition of a given resource option:

Reliability benefit = Increase in Expected Time Interval Between Loss of Load Events

$$= (1/LOLE)_{\text{with added resource option}} - (1/LOLE)_{\text{base case}}$$

or

Reliability benefit = MWh/yr of avoided unserved energy

$$= (LOEE)_{\text{base case}} - (LOEE)_{\text{with added resource option}}$$

where,

LOLE = Loss of Load Expectation (days/year or occurrence/year)

[15] Loss of load expectation is the probability that load cannot be met, whereas unserved energy or loss of energy expectation (LOEE) is the energy that would have been consumed had there been no probabilistic loss of load.

1/LOLE = Expected Time Interval Between Loss of Load Events (years/occurrence)

LOEE = Loss of Energy Expectation (MWh/year)

The cost component of the cost-benefit analysis considers the total net costs over the economic life of the resource option, which is reflected in the net cost of capacity (levelized). The net cost of capacity can be defined as follows:

<u>Generation and Demand Side Options</u>

Net cost of capacity ($/kW-yr) = Levelized Carrying Charge + Levelized Fixed O&M – (Levelized Annual Energy Revenues or Savings – Fuel Cost – Variable O&M)

Note that for the repowering option the energy benefits will be incremental. In other words, the economic benefits reflect the net increase in energy benefits due to repowering, rather than total plant energy revenues. This net increase comes from two sources:

- Repowering reduces the plant heat rate (often appreciably) and allows the plant to run more during the year
- Repowering increases the capacity of the unit and additional revenues are also earned on the incremental capacity

<u>Transmission Options</u>

Net cost of capacity ($/kW-yr) = Levelized Carrying Charge of Transmission + Levelized Fixed O&M of Transmission + Cost of Contracted (i.e., Firm) Generating Capacity – Energy Savings

The "Energy Savings" term for transmission options refers to the difference in the wholesale cost of electricity generation between the injection and discharge points of the transmission line.

Having defined how the costs and benefits are to be quantified, a cost-benefit ratio can then be formulated:

$$\text{Cost to Benefit (C/B) Ratio} = \frac{\text{Net cost of capacity}}{\text{Reliability benefit}}$$

Depending on which reliability benefit is used (increase in expected time interval between loss of load events or reduction in unserved energy) the units of the C/B ratio will be in terms of annual dollars to achieve one additional year in expected time interval between loss of load events or annual dollars to avoid one MWh of unserved energy per year.

3.0 Resource Adequacy Analysis – Base Case

3.1 Base Case Assumptions

The SRAS base case utilizes the NYISO base case peak load forecast from the RNA.[16] The base case peak forecast is shown in Figure 2. The zonal peak loads in Figure 2 are coincident with the NYCA peak.[17]

The NYISO base case peak load forecast shows that the Lower Hudson Valley (i.e., zones G through I) will experience the highest compounded annual growth rate (CAGR) from 2004 through 2015 at 2.4%. Over this same period, the estimated CAGR for New York City (zone J), Long Island (zone K), Upper Hudson Valley (zone F), the West (zones A through E) and NYCA are 1.2%, 1.6%, 1.6%, 0.2% and 1.2% per year, respectively. New York City peak load is expected to grow at the same rate as NYCA's, whereas the peak loads in New York City's neighboring areas (Long Island and the Lower Hudson Valley) are expected to grow at a faster rate.

Figure 2. Base Case Peak Load Forecast

Regional Summer Peak Load Forecast (MW) Before Reductions for Emergency Demand Response Program						
	Load Zone					
Year	**A - E**	**F**	**G - I**	**J**	**K**	**NYCA**
2005	8,905	2,100	4,410	11,315	5,230	31,960
2006	8,930	2,129	4,516	11,505	5,320	32,400
2007	8,987	2,158	4,624	11,660	5,410	32,840
2008	9,102	2,188	4,735	11,805	5,500	33,330
2009	9,158	2,218	4,849	11,965	5,580	33,770
2010	9,216	2,249	4,965	12,090	5,680	34,200
2011	9,220	2,280	5,084	12,217	5,779	34,580
2012	9,209	2,311	5,206	12,294	5,879	34,900
2013	9,098	2,343	5,331	12,426	5,981	35,180
2014	8,941	2,376	5,459	12,559	6,085	35,420
2015	8,911	2,408	5,590	12,648	6,112	35,670

Source: NYISO's *Comprehensive Reliability Planning Process Supporting Document and Appendices For The Draft Reliability Needs Assessment,* dated 12/21/2005.

[16] Con Edison's internal base case peak load forecast for zone J (i.e., New York City) matches the NYISO base case peak load forecast through 2010, but over the 2011 to 2015 period the Con Edison forecast is about 30 MW higher on average than the NYISO forecast for zone J.
[17] The zone J peak has typically been coincident with the NYCA peak.

Figure 3 shows the percentage distribution of the NYCA peak load across all the zones. This shows that the higher growth rate in the Lower Hudson Valley (i.e., zones G through I) will cause it to become a larger share of the NYCA load over time. Because the growth rate in New York City approximates that of NYCA, New York City's share of the NYCA load remains constant over time.

Figure 3. Distribution of NYCA Load Across Load Zones

Regional Summer Peak Load Forecast (% of NYCA) Before Reductions for Emergency Demand Response Program						
	Load Zone					
Year	**A - E**	**F**	**G - I**	**J**	**K**	**NYCA**
2005	27.9%	6.6%	13.8%	35.4%	16.4%	100%
2006	27.6%	6.6%	13.9%	35.5%	16.4%	100%
2007	27.4%	6.6%	14.1%	35.5%	16.5%	100%
2008	27.3%	6.6%	14.2%	35.4%	16.5%	100%
2009	27.1%	6.6%	14.4%	35.4%	16.5%	100%
2010	26.9%	6.6%	14.5%	35.4%	16.6%	100%
2011	26.7%	6.6%	14.7%	35.3%	16.7%	100%
2012	26.4%	6.6%	14.9%	35.2%	16.8%	100%
2013	25.9%	6.7%	15.2%	35.3%	17.0%	100%
2014	25.2%	6.7%	15.4%	35.5%	17.2%	100%
2015	25.0%	6.8%	15.7%	35.5%	17.1%	100%

Figure 4 compares the assumptions regarding additions and retirements between the SRAS base case and the NYISO RNA base case. The NYISO did not include the M29 Transmission Project (Sprain Brook to Sherman Creek 345/138-kV circuit) in the RNA base case because it did not have an approved System Reliability Impact Study (SRIS) at the time the NYISO finalized its base case assumptions. Since then, the SRIS for the M29 Transmission Project was approved by the NYISO Operating Committee (OC) at the July 28, 2005 OC meeting and is therefore reflected in the SRAS.

Figure 4. Differences Between NYISO RNA Base Case and Con Edison SRAS Base Case

***Note*: Yellow-highlight indicates difference between NYISO CRPP and Con Edison SRAS**

	Zone	In-Service Date	MW Capacity Summer	MW Capacity Winter	NYISO RNA	Con Edison SRAS
1. Generation						
A. Additions						
Con Edison - East River Repowering	J	Apr-05	288	288	X	X
NYPA - Poletti Expansion	J	Jan-06	500	500	X	X
SCS Energy - Astoria Energy	J	Apr-06	500	500	X	X
PSEG – Bethlehem	F	Jul-05	750	750	X	X
Calpine - Bethpage 3	K	May-05	79.9	79.9	X	X
Pinelawn - Pinelawn Power 1	K	May-05	79.9	79.9	X	X
Caithness Energy - Caithness LI (rating from SRIS)	K	May-08	310	310		X
NYPA Request for Proposal (RFP) for 500 MW – (New In-City Unit)	J	Jan-10	500	500		X
B. Retirements						
Con Edison - Waterside 6, 8, 9	J	May-05	167.2	167.8	X	X
PSEG Power - Albany 1, 2, 3, 4	F	Feb-05	312.3	364.6	X	X
NYPA - Poletti 1	J	-	885.3	885.7	X (out Feb. 2008)	X (out Jan. 2010)
RGE - Russell Station	B	Dec-07	238	245	X	X
NRG - Huntley 63, 64	A	Nov-05	60.6	96.8	X	X
NRG - Huntley 65, 66	A	Nov-06	166.8	170	X	X
Mirant - Lovett 5	G	Jun-07	188.5	189.7	X	X
Mirant - Lovett 3, 4	G	Jun-08	242.5	244	X	X
2. Transmission (Affecting Import Capability to Zones J and K)						
A. Additions						
AE Neptune PJM - LI HVDC Line	PJM to K	Jun-07	660	660	X	X
Con Edison M29 (Sprain Brook to Sherman Creek)	I to J	Spring-08	345*	345*		X

* 345 MW expected increase in NYC cable interface (from SRIS); 500 MW thermal rating of cable

With respect to the retirement of the New York Power Authority (NYPA) Poletti 1 unit, the NYISO assumed a retirement date of February 2008 even though it would result in an immediate reliability need. This, however, is contrary to the Poletti 1 retirement provision in the Article X approval of the 500 MW Poletti Expansion Project[18] which states that retirement can be delayed until 2010 if the plant is needed to comply with New York City's LCR. Therefore, the SRAS assumes that the retirement date of the Poletti 1 unit will be January 2010 based upon the present load and capacity projections.

The Caithness Project was included in the SRAS base case as it has a long-term power purchase agreement to sell almost 90% (277 MW) of the plant's capacity to the Long Island Power Authority (LIPA) and on June 23, 2005 the Long Island Power Authority's Board of Trustees voted to issue the Final Environmental Impact Statement (FEIS) for the Caithness Long Island Energy Center.

3.2 Base Case Results

Figure 5 shows the LOLE results for each of the 11 zones in NYCA for each of the 10 years of the study period. The results show that in 2010, the NYCA LOLE will exceed the 0.1 day / year criterion, indicating a need for new resources in New York State.[19] Because in New York zonal capacity to load ratios generally decrease from west to east and from north to south, the zonal LOLEs will generally be highest in those zones located at the tail end of the NYCA transmission system, i.e., zones J and K. The NYSRC who is the reliability council in the State (and the NYISO is required to implement the NYSRC reliability rules) does not have any reliability rules that require new resources to be located in the zone with the highest zonal LOLE when the State needs new resources.

[18] Case 99-F-1627, "Opinion and Order Granting a Certificate of Environmental and Public Need Subject to Conditions", page 11 states: "The Supplemental Joint Stipulation contemplates that the existing Poletti plant will cease operations as early as February 1, 2008, but no later than January 31, 2010, depending upon a determination of when closure of that plant would not impair electric service reliability in New York City. To that end, NYPA is committed to filing, by July 1, 2005, an application for a Certificate to construct a replacement combined cycle generation facility, unless there has been a determination that such replacement capacity is not needed to meet NYPA's commercial obligations or to maintain service reliability.

[19] ISO-NE has indicated at the 9/7/05 Regional System Plan public meeting that New England needs new capacity by 2010. MAAC (i.e., PJM-East) in its 2005 EIA-411 filing indicates need for new capacity by 2010. See Appendix E, which shows the MAAC and New England resource situation through 2015.

Figure 5. Base Case LOLE Results

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Zone-A	0	0	0	0	0	0	0	0	0	0
Zone-B	0	0	0	0	0	0	0	0	0	0
Zone-C	0	0	0	0	0	0	0	0	0	0
Zone-D	0	0	0	0	0	0	0	0	0	0
Zone-E	0	0	0	0	0	0	0	0	0	0
Zone-F	0	0	0	0	0	0.001	0.001	0.001	0.004	0.002
Zone-G	0	0	0	0	0.009	0.012	0.026	0.07	0.168	0.283
Zone-H	0	0	0	0	0.004	0.005	0.008	0.011	0.015	0.013
Zone-I	0	0.002	0.004	0.011	0.132	0.212	0.397	0.748	1.448	1.989
Zone-J	0.001	0.002	0.003	0.007	0.1	0.159	0.283	0.535	1.046	1.451
Zone-K	0.031	0.003	0.002	0.01	0.07	0.126	0.256	0.503	1.022	1.406
NYCA	0.032	0.006	0.006	0.016	0.163	0.26	0.477	0.885	1.679	2.272

In order to determine the future resource needs of New York City, GE ran MARS simulations consistent with the Unified Methodology that the NYSRC and the NYISO will be using to establish the 2006 IRM and LCRs, respectively.[20] In the Unified Methodology, various combinations of IRMs and LCRs would meet the LOLE criterion of 0.1 day / year.[21]

In calculating the LCRs, the SRAS base case assumes the IRM would remain at 18% (which has been the case since 2000). However, the LCRs were also calculated at 17% IRM as a sensitivity case.

Figure 6 shows the New York City LCR at 18% IRM to be 79.9%, which would increase to 80.4% if the statewide IRM were to be lowered to 17%.[22] The corresponding Long Island LCRs are also shown on Figure 6. Figure 7 shows that to keep the IRM constant at 18% IRM over time, the New York City LCR would increase from 79.9% in 2010 to 83.5% in 2015, and the Long Island LCR would increase from 97.4% to103.5% over the same period. The LCRs have to increase if the IRM remains constant over

[20] The NYSRC Executive Committee at its June 10, 2005 meeting approved the use of the Unified Methodology, which would establish an LCR vs. IRM curve such that any point along the curve would meet the NYCA LOLE criterion of 0.1 day / year. See Appendix B for procedure to develop the LCR vs. IRM curve using the Unified Methodology. The Unified Methodology requires both the LCRs and IRM be determined by adjusting capacity to reach 0.1 day / year criterion. Because the NYCA system starts with an “as found” LOLE of other than 0.1 day / year, the IRM and LCR (which establish minimum installed capacity requirements) could be determined by adjusting capacity or load in the State and in the zones with locational requirements (i.e., New York City and Long Island). Previously, the NYSRC would adjust load to determine the IRM, whereas the NYISO would adjust capacity to determine the LCRs.
[21] The NYSRC Executive Committee at its August 12, 2005 meeting approved the use of Tangent 45° anchoring method for 2006 only, which would establish the base case IRM at the point of the LCR vs. IRM curve with a slope that crosses the x-axis at 45°. See Appendix F for illustrative example of an LCR vs. IRM curve and Tangent 45° anchor. The NYSRC will revisit the anchoring method next year.
[22] The NYSRC, in its 2006 IRM study, determined that at 18% IRM the LCR for New York City would be about 82%. However, with M29 coming on line in Spring 2008 and the Neptune project coming on line in 2007 the LCR should be reduced and, as a result, in 2010 the LCR for New York City in the SRAS is shown to be about 80%.

the 2010-2015 period in order to meet the reliability criterion of 0.1 day / year LOLE in the State, because no additional transmission into New York City and/or Long Island is expected during this period.

Figure 6. LCRs Vary With IRM

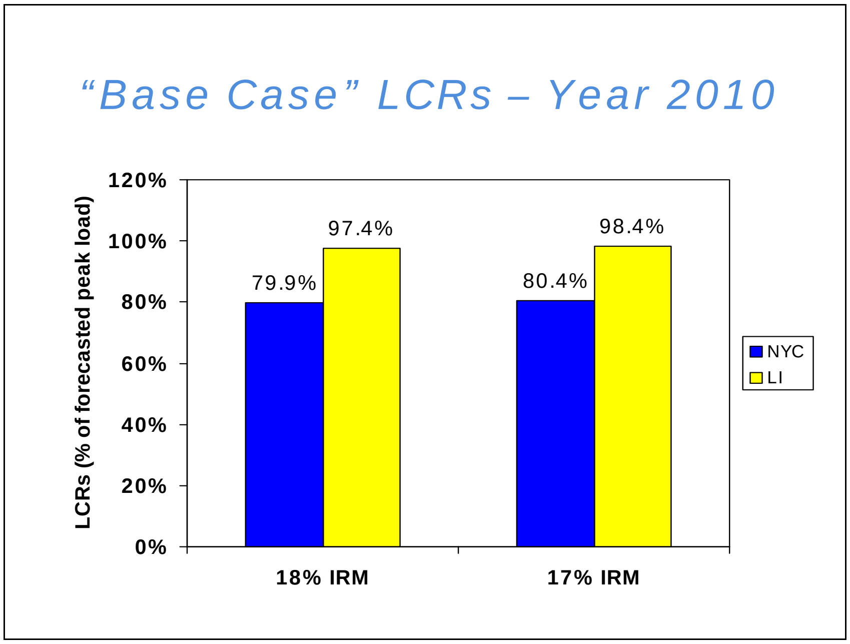


Figure 7. LCRs Vary With Time

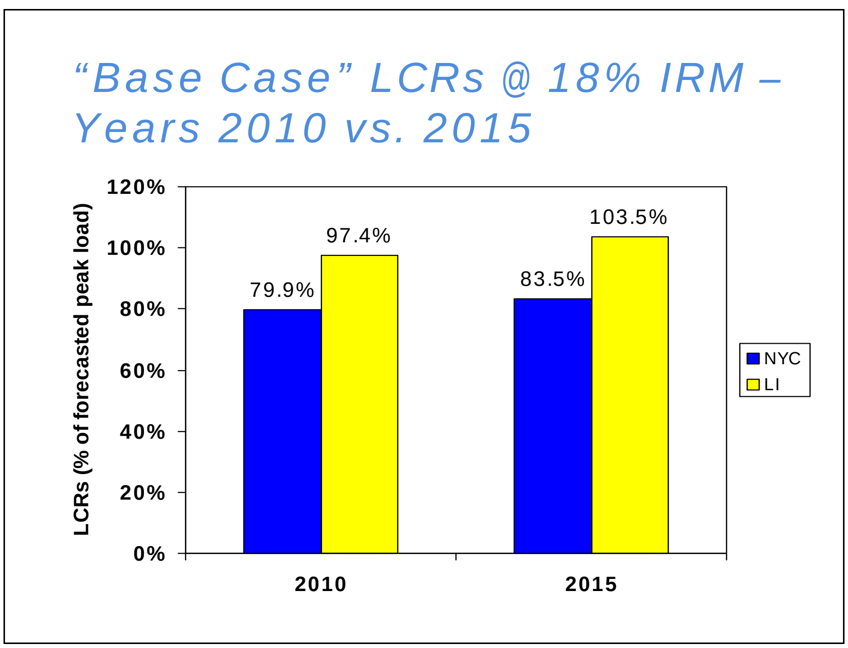
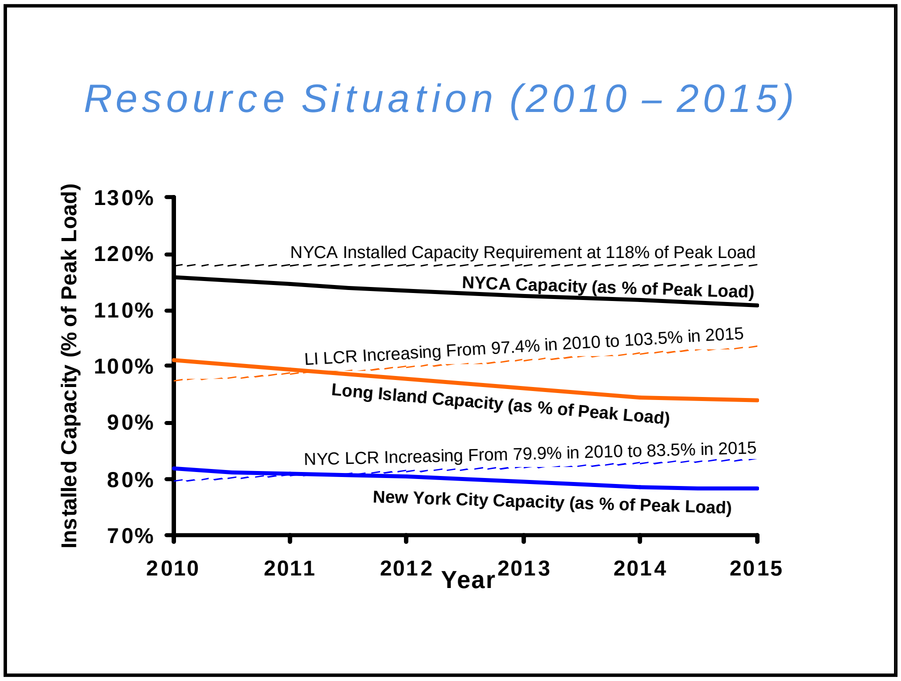


Figure 8 shows the resource situation from 2010 to 2015 for NYCA as a whole (including New York City and Long Island areas) assuming the IRM remains at 18% constant over the period. It shows that NYCA is expected to have an increasing need for new resources starting in 2010, but New York City and Long Island do not need additional locational capacity until 2012. Based on the resource situation shown on Figure 8, the need for new resources in terms of MW capacity is shown on Figure 9.

Figure 8. NYCA, NYC and LI Resource Situation



While Figure 9 shows a need for 770 MW in NYCA in 2010 assuming an 18% statewide IRM, there is enough locational capacity in New York City and Long Island in 2010 but not beyond to support a statewide IRM lower than 18%, such as 17% which would still allow an LOLE of 0.1 day / year to be attained. Therefore, to meet 0.1 day / year LOLE (absent of IRM and LCRs) in 2010, the 770 MW need as shown in Figure 9 would be reduced to 430 MW, which differs from the 1,250 MW identified need for 2010 in the RNA by the 500 MW NYPA RFP and the 310 MW Caithness plant assumed in the SRAS base case but were not in the RNA.

Figure 9. NYCA, NYC and LI Resource Needs

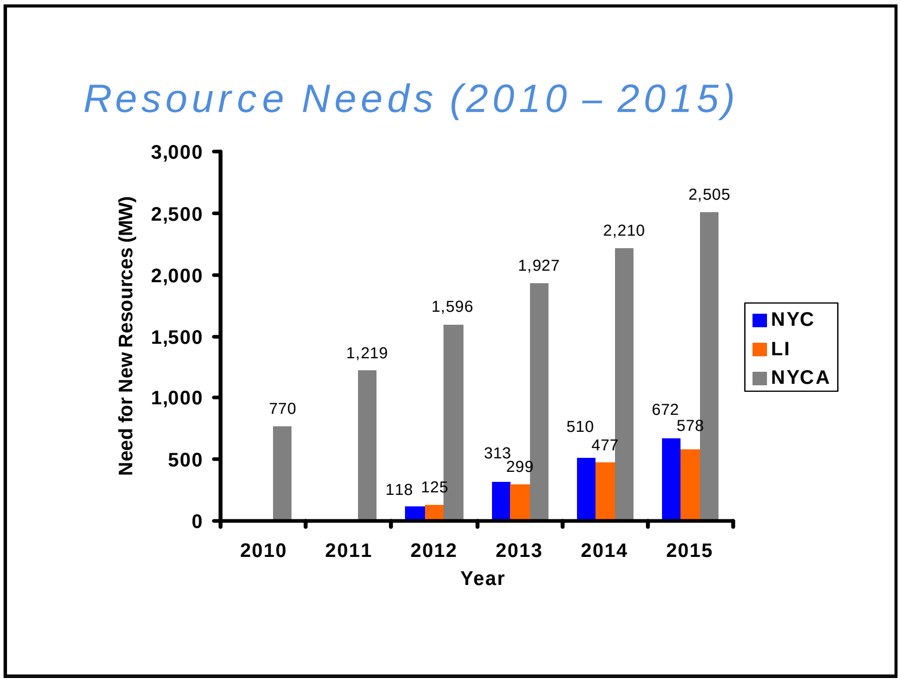
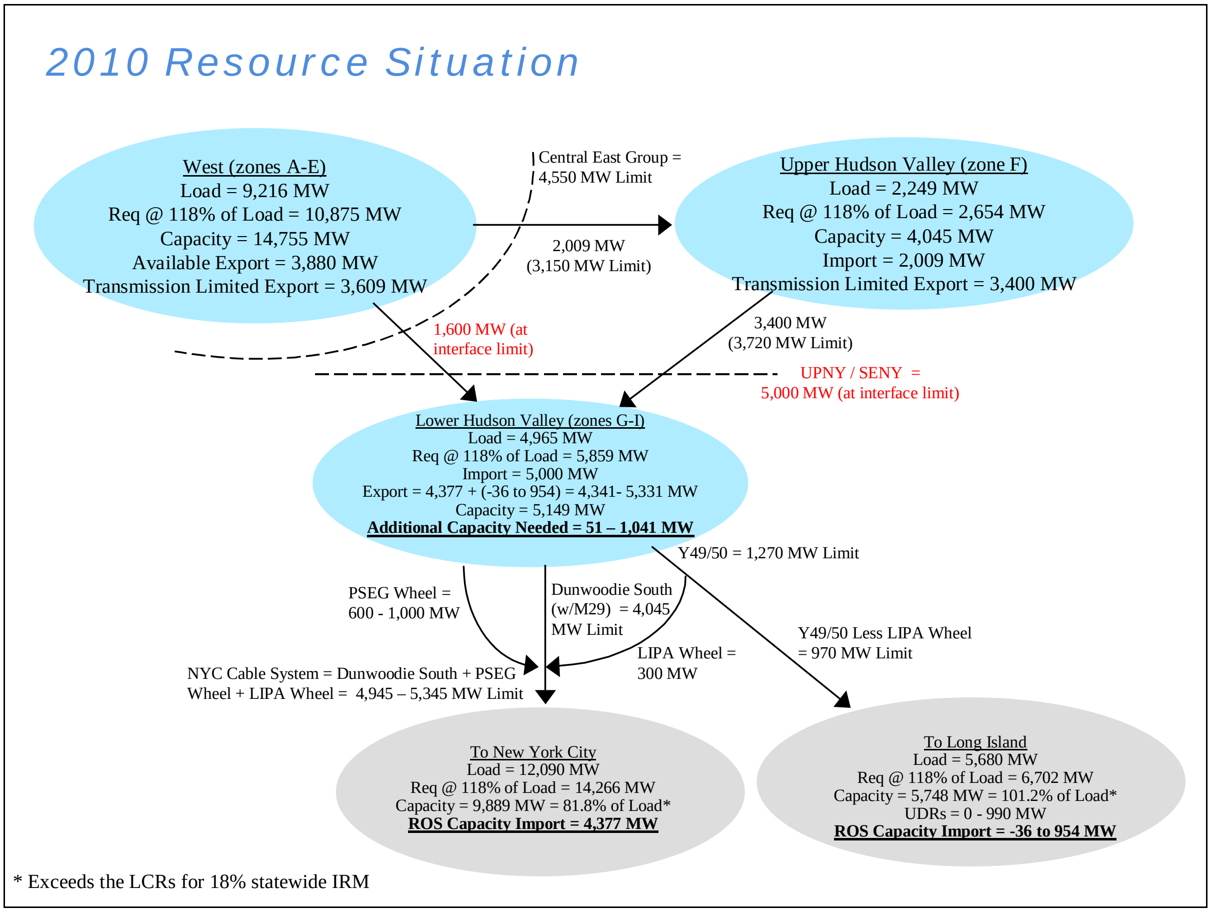


Figure 10 shows resources in western New York (i.e., zones A through E) may be limited at the UPNY/SENY transmission interface into the Lower Hudson Valley, which needs new resources by 2010. Without new resources in the Lower Hudson Valley, import into New York City and Long Island would be limited by generating supply in the Lower Hudson Valley and not by transmission capacity into New York City and Long Island.

As shown on Figure 10, the amount of new resources needed in the Lower Hudson Valley depends on the amount of unforced capacity deliverability rights (UDRs) that the Long Island Power Authority (LIPA) can obtain, which affects the import LIPA would need from the Lower Hudson Valley. In order to obtain the 330 MW of Cross Sound Cable UDRs and the 660 MW of Neptune Cable UDRs, there must be capacity at the other end of those transmission cables in Connecticut and New Jersey, respectively. However, both New England and PJM have expressed a need for new capacity for themselves by 2010 (see Appendix E) and as a result, the LIPA UDRs should not be included for long-term planning unless LIPA can demonstrate that it has firm capacity contracts for generation in New England and/or PJM to allow it to make use of its UDRs.

Figure 10. New Resources Needed in Lower Hudson Valley



MARS simulations show that increasing the UPNY/SENY interface by 500 MW would reduce the NYCA LOLE in 2010 from 0.163 to 0.073, which would allow NYCA to meet the 0.1 day / year LOLE criterion. However, adding a 500 MW HVDC line from zone G to zone J in MARS simulations, with or without firm generating capacity[23], would have no effect on the NYCA LOLE in 2010, which means that there is insufficient generating capacity in the Lower Hudson Valley to support the export to New York City. On other hand, adding 500 MW of new generating capacity in the Lower Hudson Valley without new transmission would reduce the NYCA LOLE by an amount comparable to the LOLE reduction from adding 500 MW of new generating capacity in New York City. 500 MW of new generating capacity in the Lower Hudson Valley would reduce the NYCA LOLE in 2010 from 0.163 to 0.065, whereas 500 MW of new generating capacity in New York City would reduce the NYCA LOLE in 2010 from 0.163 to 0.060.

[23] Firm generating capacity is capacity that is either owned or contracted for, but the capacity does not have to be from new generation.

Over the 2006 – 2015 period, as shown on Figure 2 the Lower Hudson Valley (i.e., zones G through I) is expected to see almost 1,200 MW load growth from 2005 level, which would require about 1,400 MW of capacity. As shown on Figure 9, outside of New York City and Long Island, in 2015 new resources equal to 1,255 MW (i.e., 2,505 MW statewide less 672 MW New York City less 578 MW Long Island) would be required just to meet load growth in the Lower Hudson Valley. Placing new generation in the Lower Hudson Valley would not only meet load growth in that area, but also would provide critical reactive power in the Lower Hudson Valley and support transfer capability to New York City and Long Island.

4.0 <u>Resource Adequacy Analysis – Sensitivity Cases</u>

4.1 **NYISO RNA**

The NYISO RNA examined the effect of transmission limitations on resource needs by using three different sets of transmission transfer limits:

- Free-flowing, which assumes no transmission limitations within NYCA
- Thermally constrained limits only, which assumes any voltage concerns would have already been addressed
- The most limiting thermal or voltage constraint

From the NYISO's "CRPP Supporting Document and Appendices for the Draft RNA" (December 21, 2005 release), the first year of resource deficiency determined by using thermal transfer limits, is 2009, with the corresponding NYCA LOLE of 0.160. Figure 11 below shows results from NYISO's RNA study.

Figure 11. NYISO RNA LOLE Results Showing Need Date of 2009

AREA OR POOL	2006	2007	2008	2009	2010
Zones A – E	0.000	0.000	0.000	0.000	0.000
Zone F	0.000	0.000	0.000	0.000	0.000
Zone G	0.000	0.000	0.000	0.001	0.017
Zone H	0.000	0.000	0.001	0.001	0.007
Zone I	0.000	0.001	0.038	0.088	0.505
Zone J	0.000	0.001	0.055	0.124	0.583
Zone K	0.021	0.002	0.029	0.070	0.309
NYCA	0.021	0.003	0.073	0.160	0.752

The SRAS identifies the first year of need for new resources for NYCA as 2010 (see Figure 5 in Section 3.2), with a NYCA LOLE of 0.163.

The differences between the SRAS and RNA regarding when new resources are needed is a result of more capacity being available for 2009 in the SRAS base case compared to the NYISO RNA base case. In both cases the need is triggered by the retirement of the 885 MW Poletti 1 unit. In the SRAS this occurs in 2010 whereas the NYISO RNA base case retires this unit in 2008. In addition, the SRAS base case assumes a new 500 MW in-City unit (NYPA RFP) coming on line in 2010.

Another new capacity addition that is in the SRAS base case, but not in the NYISO RNA base case, is the 310 MW Caithness plant on Long Island. The SRAS base case assumes this plant will begin commercial operation in 2008. This plant, however, is expected to be of little benefit in mitigating for the retirement of Poletti 1 because it is located beyond the constrained transmission interface and therefore unable to offer significant capacity to the City.

4.2 High Load Growth

The SRAS also examined the resource adequacy needs under the NYISO's high load growth peak load forecast. The NYCA peak load CAGR under the high load growth forecast is estimated at 1.5% between 2004 and 2015, as compared to 1.2% under the base case peak load forecast. Assuming the same percentage distribution of the NYCA peak load across the zones as shown on Figure 3, the high load growth peak load forecast is shown below on Figure 12.

Figure 12. High Load Growth Peak Load Forecast

Regional Summer Peak Load Forecast (MW) Before Reductions for Emergency Demand Response Program						
	Load Zone					
Year	**A - E**	**F**	**G - I**	**J**	**K**	**NYCA**
2005	8,973	2,116	4,444	11,401	5,270	32,204
2006	9,030	2,153	4,566	11,634	5,379	32,762
2007	9,128	2,192	4,697	11,844	5,495	33,357
2008	9,274	2,229	4,825	12,028	5,604	33,961
2009	9,358	2,266	4,955	12,226	5,702	34,508
2010	9,447	2,305	5,089	12,393	5,822	35,057
2011	9,480	2,344	5,227	12,562	5,942	35,556
2012	9,496	2,383	5,368	12,677	6,062	35,987
2013	9,406	2,422	5,512	12,847	6,184	36,372
2014	9,266	2,462	5,658	13,016	6,306	36,709
2015	9,259	2,502	5,808	13,142	6,351	37,063

The results of the MARS simulations for the high load growth sensitivity case are shown on Figure 13. These results indicate that the first year when additional resources are needed for NYCA remains at 2010 and this need is triggered by the retirement of Poletti 1, as stated earlier. However, in this case the need for capacity is greater.

A comparison of the base case peak load forecast (Figure 2) and the high load growth peak load forecast (Figure 12) shows that the NYCA peak load in 2010 under the high load forecast is 857 MW higher, which would have similar reliability impact as retiring about 1,000 MW of generating capacity under the base load peak load forecast after considering reserve requirements. Since about half of the load is in New York City and Long Island, the results of the high load growth sensitivity case should also be indicative of the reliability impact of retiring 500 MW of generating capacity in either New York City or Long Island and another 500 MW of generating capacity in the other load zones in NYCA under the base case.

Figure 13. SRAS High Load Growth LOLEs Indicate Need Year Would Remain at 2010

AREA OR POOL	2006	2007	2008	2009	2010
Zones A – E	0.000	0.000	0.000	0.000	0.000
Zone F	0.000	0.000	0.000	0.000	0.000
Zone G	0.000	0.000	0.000	0.001	0.015
Zone H	0.000	0.000	0.000	0.001	0.004
Zone I	0.001	0.004	0.007	0.021	0.219
Zone J	0.004	0.004	0.005	0.014	0.160
Zone K	0.071	0.007	0.006	0.018	0.138
NYCA	0.075	0.012	0.011	0.031	0.271

4.3 **Summer 2005 Experience**

Both the Con Edison SRAS and the NYISO RNA use a peak load forecast for NYCA and its individual load zones, which was developed by the NYISO prior to Summer 2005. Con Edison is in no position to develop peak load forecasts for NYCA and/or the load zones outside of its service areas and, as a result, Con Edison is dependent on the NYISO for its peak load forecast as it applies to the reliability analysis in the SRAS. However, Con Edison's analysis of the Summer 2005 experience shows that the weather adjusted actual peak load in New York City came in at 11,415 MW, which is 100 MW higher than was forecast by the NYISO. Also, the amount of SCRs registered in New York City during Summer 2005 was about 300 MW, which is 128 MW higher than the 172 MW assumed in both the Con Edison SRAS and the NYISO RNA. This suggests the SRAS results, at least for New York City, remain valid in light of the Summer 2005 experience, because the higher in-City load is offset by the higher amount of SCRs available in the City. Without an updated forecast of the entire NYCA and its individual zones, which the NYISO will be preparing early next year, the SRAS cannot redo the reliability analysis incorporating the Summer 2005 experience.

5.0 Resource Options Analysis

5.1 Range of Options Considered

This part of the study focuses on identifying resource options that could be installed in New York City within the next 10 years and evaluating their cost effectiveness in maintaining the reliability of the New York bulk power system. The approach, outlined in Section 2.3.3 above, is to determine the net cost of installing each resource per unit of "reliability benefit". Hence, the benefit in question is not an economic benefit but rather a quantifiable measure of reliability improvement to New York's bulk power system.

The supply and demand resource options to be considered in the study were selected through a collaborative effort involving Con Edison and the SRAS Collaborative. The list of options considered provides a broad range of options. While the list may not explicitly identify all options that may be viable in New York City, the breadth of the list should bound the potential options. For example, while phosphorous acid fuel cells are not explicitly analyzed, their costs fall about midway between those of molten carbonate (MC) fuel cells and internal combustion (IC) engines, which would place their cost-benefit ratio about midway between those of molten carbonate fuel cells and internal combustion engines.

The Collaborative determined that the options shown on Figure 14 below best represent resources that are deemed to be technologically feasible for New York City within the time horizon of the study. While it is outside the scope of the SRAS to address voltage requirements, it should be noted that out-of-City generation imported over transmission lines does not provide critical reactive power to the City to support load growth.

Central station co-generation combined cycle plants were considered to be a variation of how Combined Cycle Gas Turbine (CCGT) plants are operated. For example, the new KeySpan Ravenswood unit that began commercial service in 2004 is a co-generating combined cycle unit that is operated to produce electricity-only with no steam host. Therefore, the co-generation plant has been addressed in the SRAS as a variation in operation of the CCGT and not as a separate resource option.[24] CCGT co-generating plants, when operated at their maximum electric output (i.e. electric only), will provide the same electric reliability benefit as an electric only CCGT plant.

[24] In order for a CCGT to operate in co-generating mode, it would need a steam host.

Figure 14. Resource Options Considered in the Study

New Central Station Generation	Simple Cycle Gas Turbine (SCGT)
	Combined Cycle Gas Turbine (CCGT)
	Out-of-city SCGT with radial tie (SCGT + AC)
	Out-of-city CCGT with radial tie (CCGT + AC)
Re-powered Central Station Generation	Combined Cycle Gas Turbine (CCGT Repowering)
Transmission with Firm Generating Capacity	AC line with phase angle regulator to PJM (AC Line – PJM)
	AC line with phase angle regulator to Lower Hudson Valley (AC Line – LHV)
	High Voltage Direct Current line to PJM (HVDC – PJM)
	High Voltage Direct Current line to Lower Hudson Valley (HVDC – LHV)
Distributed Generation	Microturbine
	Microturbine Combined Heat and Power (CHP)
	IC Engine (natural gas fired)
	IC Engine CHP (natural gas fired)
	Molten Carbonate (MC) Fuel Cell
	Molten Carbonate (MC) Fuel Cell CHP
	Solar Photovoltaic (PV)
Demand Side Measures	Commercial HVAC
	Commercial Lighting
	Motors
	Residential HVAC
	Residential Lighting

5.2 **Cost Assumptions**

Plant capital and O&M costs assumptions, initially developed by Con Edison were reviewed by the SRAS Collaborative. Valuable input from Collaborative members was then incorporated into the study and the initial assumptions were modified to obtain the final cost assumptions presented on Figure 15.

Figure 15. Resource Cost Assumptions, Uncertainty Values, and Unit Heat Rate Data

	Capital Cost (US dollars per kW)	Uncertainty +/- fraction	Economic Life (years)	Fixed O&M Cost (dollars per kW-yr)	Cost of Firm Gen. Capacity (dollars per kW-yr)	Uncertainty +/- fraction	Variable O&M Cost (dollars per MWh)	Uncertainty +/- fraction	Electric Heat Rate Btu/kWh	Sources (see Appendix D for references)
New Central Station Generation										
Combined Cycle GT	1,450.00	0.15	30	43		0.15	2	0.25	6,204	Reported costs for KeySpan and Poletti CC plants and ERRP + input from NYCEDC
Gas simple-cycle	1,200.00	0.15	30	38		0.15	4	0.25	8,979	2004 Levitan report for NYISO
Out of City CCGT + AC Trans	1,430.00	0.25	30	34		0.25	2	0.25	6,396	Estimated Northern NJ plant costs through comparative analysis + input from NYCEDC
Out of City SCGT + AC Trans	1,240.00	0.25	30	32		0.25	4	0.25	9,257	Estimated Northern NJ plant costs through comparative analysis + input from NYCEDC
Repowered Central Station Generation										
Combined Cycle GT	1,840.00	0.25	30	40		0.25	0	-	6,204	Public Power
Transmission										
AC Line with firm generating capacity (Lower Hudson Valley)	500.00	0.40	30	15.00	87.00	0.40	0	-	-	Platts + input from NYCEDC
AC Line with firm generating capacity (PJM)	500.00	0.40	30	15.00	72.00	0.40	0	-	-	Platts + input from NYCEDC
HVDC with firm generating capacity (Lower Hudson Valley)	640.00	0.50	30	19.20	87.00	0.50	0	-	-	Neptune line estimated project cost + input from PSC Staff on uncertainty
HVDC with firm generating capacity (PJM)	640.00	0.50	30	19.20	72.00	0.50	0	-	-	Neptune line estimated project cost + input from PSC Staff on uncertainty
Distributed Generation										
Solar PV	11,050.00	0.50	30	0		-	0	-	-	CERA Report + NYSERDA report
Microturbine	2,350.00	0.25	20	29		0.25	2.5	0.25	12,638	CERA Report + NYSERDA report
Microturbine CHP	2,650.00	0.25	20	33		0.25	3	0.25	6,256	CERA Report + NYSERDA report
IC Engine	1,350.00	0.25	20	2.8		0.25	17	0.25	10,185	Bonneville Power Administration Report provided by E-cubed + 2004 LBNL Report
IC Engine CHP	1,420.00	0.25	20	3.3		0.25	17.5	0.25	5,755	Bonneville Power Administration Report provided by E-cubed + 2004 LBNL Report
Molten carbonate fuel cell	8,300.00	0.25	20	6.8		0.25	41.5	0.25	7,260	CERA Report + NYSERDA report
Molten carbonate fuel cell CHP	8,600.00	0.25	20	7		0.25	42	0.25	4,792	CERA Report + NYSERDA report
Demand Side Management										
Commercial HVAC	1,160.00	0.25	15	-		-	-	-	-	NYSERDA database
Commercial Lighting	7,500.00	0.25	15	-		-	-	-	-	NYSERDA database
Motors	2,150.00	0.15	20	-		-	-	-	-	NYSERDA database
Residential HVAC	2,275.00	0.50	20	-		-	-	-	-	NYSERDA database
Residential Lighting	2,400.00	0.50	10	-		-	-	-	-	NYSERDA database

a. In-City Generation

The capital and O&M costs for in-City simple cycle plants were taken from the 2004 report by Levitan and Associates titled "Independent Study to Establish Parameters of the ICAP Demand Curves for the New York Independent System Operator". The simple cycle gas turbine (SCGT) plant is based on 2XLM6000 technology (similar to the NYPA gas turbines) with a nominal capital cost estimated at $1,200/kW.

As a confirmation check, the estimated average cost for the 11 NYPA gas turbines (GTs) is: [25]

$640 million / (11 GTs x 47 MW/GT) = $1,238/kW

The CCGT plant cost had initially been taken from the Levitan report and was estimated at $1,350/kW. Based on input from NYCEDC and review of reported costs for new plants such as the SCS Astoria, KeySpan and Poletti Expansion CCGT plants, the cost estimate was revised to $1,450/kW. It is based on a 2X1 configuration with 2 7FA GTs feeding to a single steam turbine. The $1,450/kW number is also within 5% of the capital cost of the combined cycle equivalent of the Con Edison East River Repowering Project (ERRP) derived by adjusting the actual ERRP capital cost data to reflect a generic in-City combined cycle plant.

The KeySpan and Poletti Expansion cost estimates are as follows:

KeySpan CCGT:[26]	$350 million / 250 MW = $1,400/kW
Poletti CCGT:[27]	$715 million / 500 MW = $1,430/kW

In addition, a Citigroup report[28] on KeySpan Corporation released on August 8, 2005 cites the in-City replacement cost of a peaker unit at $1,200/kW, and that of base loaded generation at $1,400/kW.

In all of these cost figures the capacity at International Organization for Standardization conditions (i.e., at 59°F ambient) has been used. Both the fixed and variable O&M values were taken from the Levitan report.

b. Out-of-City Generation with Radial Transmission Line

Con Edison used estimated Northern New Jersey plant costs as a proxy for the out-of-City generation option. Beginning with cost data from the 2004 report by Levitan and Associates, Con Edison estimated Northern New Jersey costs, as follows:

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[25] Levitan report
[26] SNLi article *"KeySpan to Start up Ravenswood Plant Extension"*, March 26, 2004
[27] Public Authorities in New York State, Comptrollers Report, February 2005. *Note: Due to the delay in project completion, additional financing cost was assumed.*
[28] Analyst: Faisal Kahn, CFA

The most recent (September 1, 2004) update from Levitan shows a 2x7FA SCGT in the Albany area (zone F) to cost $599/kW, which is a $78.2 million reduction for a 336.5 MW 2x7FA SCGT from the cost reported in the August 2004 (original) Levitan report. [29] Applying the same $78.2 million reduction to the 2x7FA GT portion of the 519 MW CCGT unit in the August 2004 Levitan report shows that a 519 MW CCGT in the Albany area (zone F) would cost $750/kW. The $750/kW for CCGT in the Albany area is corroborated by the simple average of known costs of Bethlehem and Athens (both which are in the Albany area), which is $749/kW.[30]

However, the cost to build in the area of Northern New Jersey that is part of the Greater New York region is higher than in the Albany area but lower than in New York City. A comparison of the RS Means Construction Cost Indices for the Albany area (96.1), Northern New Jersey (i.e., Jersey City at 110.3) and New York City (132.4) shows that the cost differential to build in Northern New Jersey as compared to the Albany area is about 39% of the cost differential to build in New York City as compared to the Albany area.

Based on this comparison, and with the agreement of the Collaborative, the out-of-City SCGT and CCGT capital costs were determined to be $830/kW and $1,020/kW, respectively.

The radial transmission line cost from Northern New Jersey to New York City was assumed to be $410/kW, based on input from NYCEDC[31] who referenced an internal NYCEDC report prepared by its consultant. Hence, the capital cost of the out-of-City generation with radial transmission options were determined by adding the SCGT and CCGT plant capital cost to the radial transmission line capital cost yielding $1,240/kW for SCGT with a radial AC line and $1,430/kW for a CCGT with a radial AC line.

c. Repowering

The repowering option cost assumption is based on the Reliant Energy Astoria Plant repowering project.[32] The Astoria plant has four oil/gas fired steam boilers. The repowering project would retire the old boilers and add six new gas turbines and heat recovery steam generators (HRSG) to utilize two of the four steam turbines for a net capacity addition of 1,074

[29] The September 2004 update was released to correct errors in Upstate NY plant cost estimates.
[30] Draft Report by ICF Consulting, prepared for NYCEDC, “Overview of Generation and Transmission Capital Cost Assumptions for the NYC Marketplace”. Sent to Con Edison SRAS team on August 26, 2005.
[31] NYCEDC Document “Revised Cost Assumptions for Supply Side Resources”. Sent to Con Edison SRAS team on August 26, 2005.
[32] For details refer to the Article X (Case 00-F-1522) and DEC 624 issues rulings issued March 20, 2002.

MW to the two steam turbines that will be utilized. After repowering, the Reliant Energy Astoria Plant would become an 1,816 MW CCGT facility.

In the absence of exact cost data, and based on a 2002 journal article on repowering,[33] Con Edison assumed that repowering can rehabilitate and increase generating capacity at a cost that is 25% lower than new plant construction. Therefore, since the new CCGT cost has been assumed to be $1,450/kW (see discussion of in-City generation cost assumptions in "a" above), the 1,816 MW repowered plant is estimated to cost $1,087/kW (75% of $1,450) or $1.975 billion.

Since some of this capacity already exists, the total cost of repowering needs to be applied only to the incremental capacity, in this case 1,074 MW, to determine the capital cost per kW of the repowering option. Hence the cost of the repowering option is determined by dividing the $1.975 billion figure by 1,074,000 kW to obtain $1,840/kW.

d. Transmission with Firm Generating Capacity

For both the High Voltage Direct Current (HVDC) and Alternating Current (AC) transmission resource options, Con Edison assumes the transmission line to be underground going into the City. The HVDC line assumes a similar cable like the Neptune Project, which is a 65-mile, partially submerged 660 MW line. A Siemens press release[34] reports the cost at $420 million, or $640/kW, which also reflects the costs for interconnection and system upgrades.

An underground AC line would cost about $350/kW, which is based on the average of the cost of the radial transmission line discussed in "b" above and the comparable cost reported[35] to replace cable from Norwalk, CT to Northport, LI. The same underground AC line with phase angle regulator would cost about $500/kW.

Because each additional mile of underground/undersea HVDC transmission (~$3 million per additional mile) is less expensive than an additional mile of underground AC transmission (~$15 million per additional mile), Con Edison assumes that HVDC will be used primarily for longer distance transmission which would spread out the cost of the converter stations while taking advantage of the lower incremental cost per mile of HVDC cables. For shorter distance transmission, underground AC lines will be more economical, such as M29, PSEG's recently cancelled Cross Hudson Cable Project, and the proposed cable replacement from Norwalk, CT to Northport, LI, all of which were approximately 10 miles long.

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[33] "The Repowering Solution," Public Power, September – October 2002, pp. 8-12
[34] July 21, 2005 press release. Visit www.siemens.com/ptd for the link.
[35] Platts news release, "*Cross Sound Cable to Remain Open,*" 7/12/2004.

e. Distributed Generation

Initially, two sources were used to determine DG average costs: (1) "*Combined Heat and Power Market Potential for New York State*", NYSERDA Report, October 2002, and (2) May 2004 CERA Watch, "*The Narrowing Band of Competitiveness in Generation Technologies*".

Both of these sources report capital costs for Combined Heat and Power (CHP) applications using DG technologies. Costs are reported to include electrical and fuel interconnection. Con Edison took the low and high cost ranges from these reports and computed an average value for each technology.

To calculate the cost of non-CHP (electric output only) generation resource option, a Navigant report[36] was used, which estimates the cost difference between CHP and non-CHP at $230/kW.

All of the cost figures from these reports denote national average values. In order to align these costs with New York City, the values were multiplied by the City cost factor of 1.324, from the R.S. Means Building Construction Cost Data 2005 (www.rsmeans.com).

After review by the Collaborative, E-cubed provided data and references for better estimation of the natural gas fired IC Engine, and IC Engine CHP costs. This input was reflected in the cost assumptions.

f. DSM Energy Efficiency Measures

The primary source for the cost estimates of DSM energy efficiency measures is NYSERDA's internal database on demand side measures. The SRAS used NYSERDA's November 2005 internal database release on demand side measures. The demand side measure groupings used by Con Edison and types of measures included in each are shown below on Figure 16.

The following definitions have been used in developing the capital cost figures:

Capital cost per gross demand reduction: *Incremental cost of the measure divided by the incremental gross kW savings*

Capital cost per peak coincident demand reduction: *Incremental cost of the measure divided by the incremental kW savings that coincides with the system peak load*[37]

[36] Navigant Consulting, Inc. "*California Energy Commission: DG Definition and Cost-Benefit Analysis - Policy Inventory,*" July 9, 2004.

Incremental cost: *Current cost of the efficiency measure minus the current cost of the state of the art conventional measure*

Incremental savings: *kW demand reduction of the efficiency measure compared to the state of the art conventional measure*

Figure 16. DSM Measure Types Considered in the SRAS

Measure Type	Measure Description
Commercial HVAC	Air and Water Cooled Chillers
	Air-Source Unitary or Split System HVAC
	Ventilation
	ENERGY STAR Roofing
	Packaged Terminal AC or HP
	Variable Speed Drive (replace constant speed control)
	Windows - High efficiency
	Window Unit Air Conditioners
Residential HVAC	High-Efficiency Central Air Conditioning - Air-Source Unitary or Split System HVAC
	Windows - ENERGY STAR windows for residential applications
	Infiltration Reduction (weather-stripping or air sealing, conducted with blower door)
	Duct Sealing
	Furnace - Natural Gas, equipped with an Electronically Commutated Motor (ECM) blower motor
Commercial Lighting	Compact Fluorescent Lamps
	Fluorescent Fixtures
	LED Exit Signs
	LED Traffic Signals
	Metal Halide Fixtures
Residential Lighting	Halogen Infrared (HIR) lamps (in low-use residential applications)
	Compact Fluorescent Lamps
	Lighting Fixtures, Permanent (suspended, ceiling, wall, recessed, cabinet) - ENERGY STAR
	Lighting Fixtures, Portable (Torchieres) - ENERGY STAR
Motors	Open Drip-Proof (ODP)
	Totally Enclosed Fan-Cooled

g. Fuel Prices

Two different natural gas price forecasts were used in the analysis to assess the sensitivity of the results to fuel prices. The first, a relatively

[37] NYSERDA compiles these data on a statewide basis, which means the system peak load would be on a statewide basis. Because the Con Edison system peak typically occurs at about the same hour during the day as when the NYCA system peak occurs, the NYSERDA data on system peak load impact were used without adjustment.

current forecast (dated 8/10/2005) which assumes that future prices will be elevated due to the continuation of the current anxiety over rising oil prices and other factors. The second, a low forecast, which assumes lower natural gas prices, as might be expected with coming on-line of new LNG resources and the dissipation of current market anxieties over rising oil prices. An earlier forecast (dated January 2004) was used for the low fuel scenario.

These two forecasts are shown below on Figure 17.

Figure 17. Natural Gas Price Forecasts ($/MMBtu in nominal year dollars)

Year	Current	Low
2006	10.904	5.783
2007	11.000	5.551
2008	9.589	5.329
2009	9.103	5.275
2010	8.711	5.549

The fuel prices after 2010 are assumed to escalate at 3% per year inflation.

5.3 **Cost-Benefit Results**

Using the methodology and data described in Sections 2.3 and 5.2 above, the net cost of capacity for each resource option was calculated for two cases, based on low fuel and current fuel scenarios. Details of the cost-benefit analysis are shown in Appendix G.

The results are shown in 2005 constant year dollars on Figures 18 and 19. The plots show each result with an uncertainty band calculated as described in Appendix G.

These results show two interesting trends (assuming no incentives are paid to implement the DSM energy efficiency measures):

a. Some energy efficiency measures such as commercial HVAC, motors, and residential lighting appear attractive in the sense that their energy benefits pay for most of their installation costs, resulting in their net cost of capacity being significantly lower than the other resource options;
b. As expected, energy efficiency measures are most valuable when the fuel prices are high.

Figure 18. Net Cost of Capacity Using a Low Gas Price Scenario - $5.55/MMBtu Nominal (or $4.80/MMBtu in 2005$) in NYC in 2010.

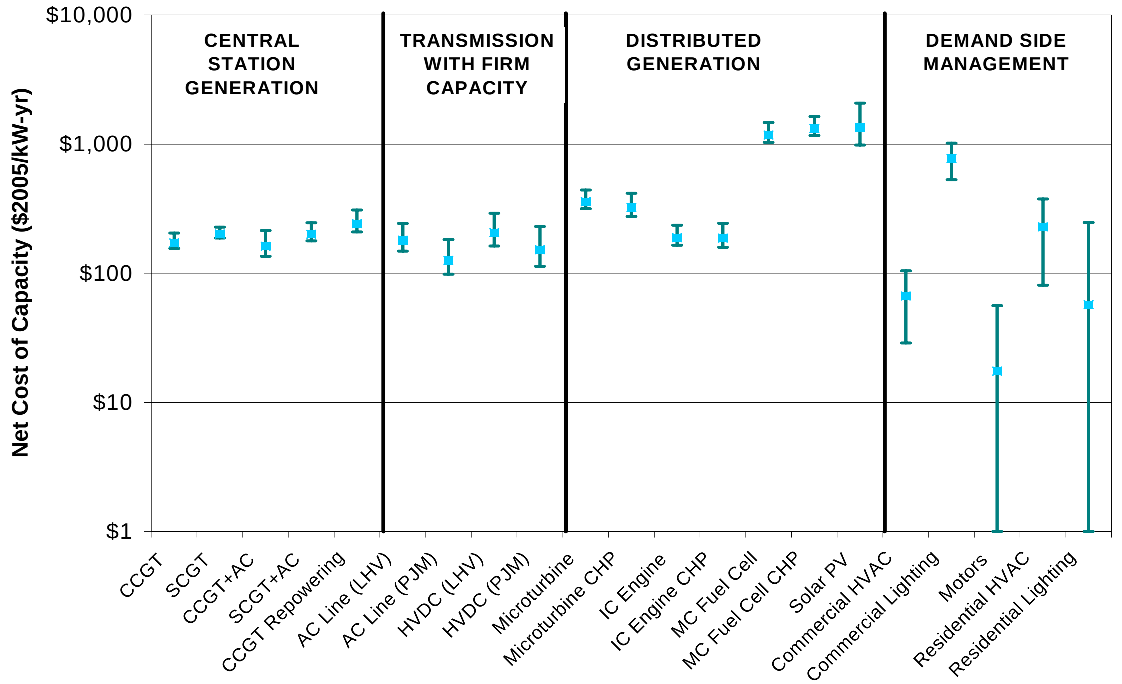
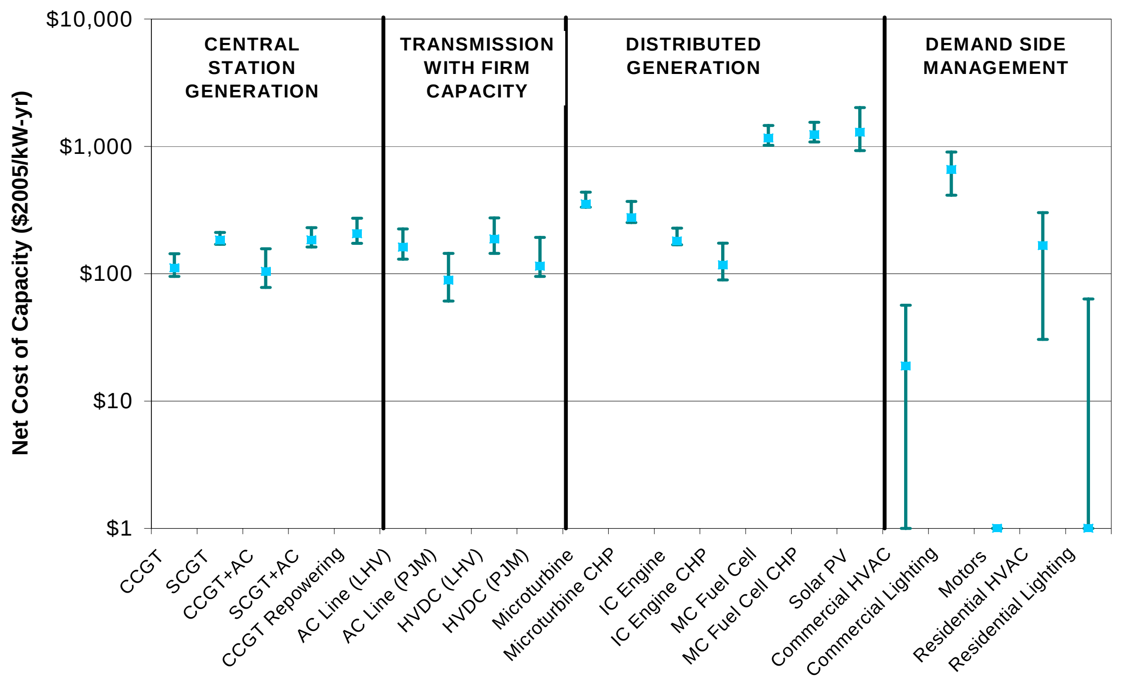


Figure 19. Net Cost of Capacity Using a Current Gas Price Scenario - $8.70/MMBtu Nominal (or $7.50/MMBtu in 2005$) in NYC in 2010.



The cost-benefit ratios are then obtained, as described in Section 2.3.3, by dividing the net cost of capacity values shown above by the reliability benefits achieved by installing each resource option.

This study used MARS to assess the reliability impact of the selected resource options in year 2010, which is the first year new resources are needed in NYCA. Based on the base case results discussed in Section 3.2, at least 430 MW of new resources would be needed in New York State in 2010 to meet the LOLE reliability criterion of 0.1 day / year. Therefore, for the analysis of the reliability benefit of the resource options, 500 MW was chosen as the capacity size to evaluate the reliability benefit of the resource options in the first year new resources are needed in NYCA, i.e., 2010. The MARS runs added 500 MW of generation or transmission capability to NYCA as follows:[38,39]

<u>Case #</u>	**<u>Sensitivity Case Description</u>**
1	GTs In-City: 10 units x 50 MW per unit
2	1 In-City CC unit: 2 GT, 2 HRSG, and 1 Steam Turbine (ST)
3	GTs outside NYC with radial tie into NYC: 10 units x 50 MW per unit
4	1 CC unit outside NYC with radial tie into NYC: 2 GT, 2 HRSG, and 1 ST
5	Transmission from PJM to NYC without Firm Supply
6	Transmission from PJM to NYC with 500 MW Firm Supply
7	Transmission from Lower Hudson Valley to NYC without Firm Supply
8	Transmission from Lower Hudson Valley to NYC with Firm Supply
9	Customer-Owned Generation (DSM)
10	Customer Energy Efficiency Measures (DSM)

Figures 20 and 21 summarize the reliability benefit to NYCA and New York City, respectively, calculated for each option for year 2010, with 500 MW capacity additions for each resource option.[40]

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[38] While 250 MW of new resource is not enough to have the NYCA meet 0.1 day / year LOLE criterion in 2010, MARS simulations were made to determine the reliability benefit of each resource option considered and their results are shown in Appendix H.
[39] Note that in-City generation would provide greater voltage support to the City.
[40] The reliability benefits in terms of LOEE from adding 500 MW of resource options are shown in Appendix H.

Figure 20 shows that there is no difference in the reliability benefit of installing a generator within New York City or a generator immediately outside of New York City with a radial transmission tie into New York City. As discussed earlier in Section 3.2, adding transmission with or without firm generating capacity between the Lower Hudson Valley and New York City has no reliability benefit to NYCA. Also, adding transmission capacity to PJM without firm generating capacity from PJM has no reliability benefit to NYCA. The in-City generating options, out-of-City generators with radial tie, transmission to PJM with firm generating capacity from PJM, and DG options have comparable reliability benefits to NYCA, with the DSM energy efficiency options providing slightly more reliability benefits to NYCA.

Figure 20. Reliability Benefit of 500 MW Resource Options to NYCA in 2010

Resource Option	Expected Time Interval Between Loss of Load Events = 1/LOLE (in years)		
	With Resource Option (i.e., Sensitivity Case)	Without Resource Option (i.e., Base Case)	Difference
SCGT	16.67	6.13	10.54
CCGT	16.67	6.13	10.54
Out-of-City SCGT with radial tie	16.67	6.13	10.54
Out-of-City CCGT with radial tie	16.67	6.13	10.54
Transmission with firm capacity (PJM)	16.39	6.13	10.26
Transmission (free-flowing) from PJM	6.13	6.13	0
Transmission with firm capacity (Lower Hudson Valley)	6.02	6.13	-0.11
Transmission (free-flowing) from Lower Hudson Valley	6.17	6.13	0.04
Customer owned generation (DG)	16.39	6.13	10.26
DSM energy efficiency	18.52	6.13	12.39

The results on Figure 21 show that the relative order of the reliability benefits of the resource options to New York City are similar to the relative order of the reliability benefits of the resource options to NYCA shown on Figure 20. However, at the New York City level, the ten 50 MW SCGT units have slightly greater reliability benefit than one 500 MW CCGT unit, which is expected due to the reliability value of many smaller units over one large unit of same total capacity. The transmission to PJM with firm generating capacity from PJM shows the greatest reliability benefit to New York City, because the 500 MW of PJM firm capacity is from a large system (i.e., PJM) which is more reliable than one or a small quantity of generating units.

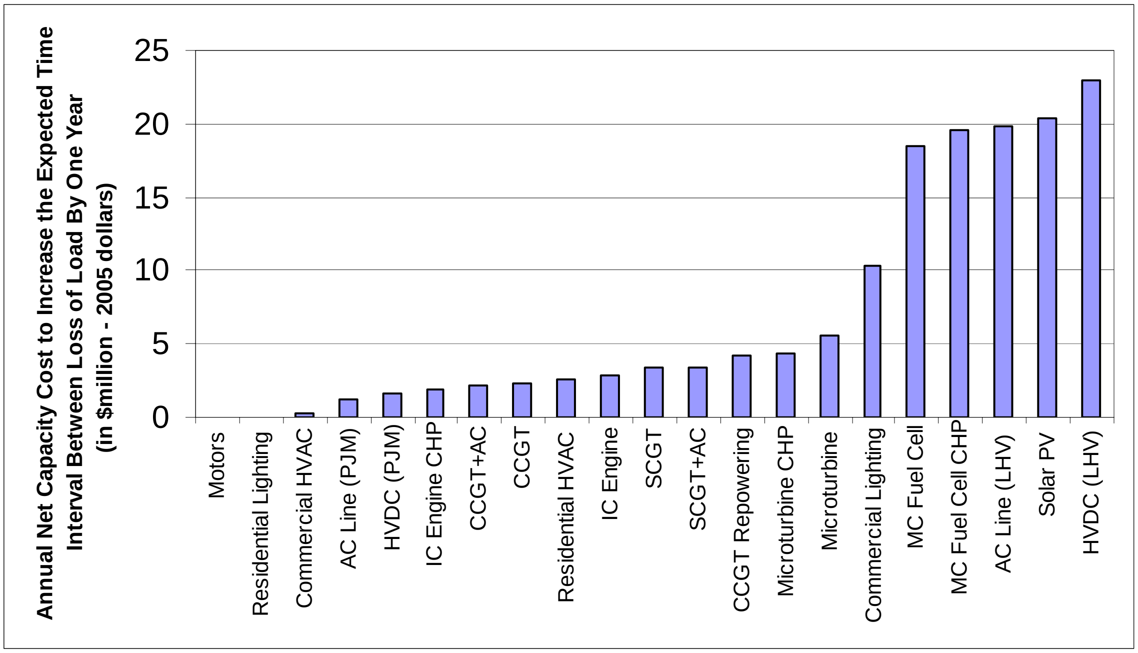
A few common observations from Figures 20 and 21 are that transmission to Lower Hudson Valley with or without firm generating capacity has little or no reliability benefit, transmission to PJM without firm generating capacity has little or no reliability benefit, and the remaining resource options considered have significant reliability benefits comparable to one another and within a relatively tight range.

Figure 21. Reliability Benefit of 500 MW Resource Options to New York City in 2010

Resource Option	Expected Time Interval Between Loss of Load Events = 1/LOLE (in years)		
	With Resource Option (i.e., Sensitivity Case)	Without Resource Option (i.e., Base Case)	Difference
SCGT	37.04	10.00	27.04
CCGT	34.48	10.00	24.48
Out-of-City SCGT with radial tie	37.04	10.00	27.04
Out-of-City CCGT with radial tie	34.48	10.00	24.48
Transmission with firm capacity (PJM)	45.45	10.00	35.45
Transmission (free-flowing) from PJM	11.90	10.00	1.90
Transmission with firm capacity (Lower Hudson Valley)	14.08	10.00	4.08
Transmission (free-flowing) from Lower Hudson Valley	11.36	10.00	1.36
Customer owned generation (DG)	41.67	10.00	31.67
DSM energy efficiency	41.67	10.00	31.67

Figure 22 shows a plot of the cost-benefit ratios calculated based on the current fuel scenario and 500 MW of capacity addition for each resource option. In the cost-benefit ratios shown, the cost is the net capacity cost of the resource option and the benefit is the reliability benefit to New York City in terms of increase in expected time interval between loss of load events as a result of adding the resource option.

Figure 22. Capacity Cost to Reliability Benefit Ratio of Resource Options



As Figure 22 illustrates, transmission from the Lower Hudson Valley to New York City is not a cost-effective option for achieving a reliability benefit. This is consistent with the SRAS base case results, presented in Section 3.2, which indicate that the Lower Hudson Valley does not have sufficient generating capacity to fully support existing transmission to New York City.

The cost to benefit ratio of transmission from PJM with firm generating capacity from PJM reflects the use of the cost of new entry, because PJM-East itself will need new resources by 2010, as shown in Appendix E. The SRAS used $72/kW-yr as the cost of new entry in New Jersey, which is based on a 7FA GT estimated by a consultant to PJM. However, this cost should be compared to the $87/kW-yr for cost of new entry in Albany, which is also based on a 7FA GT.[41,42] Because PJM-East will need new capacity by 2010, it is doubtful that firm generating capacity will be available unless new generation is built to provide the firm generating capacity. As shown in Section 5.2, it is more costly to build new generation in New Jersey than in Albany, which suggests that the cost of new entry in New Jersey should be higher than the $72/kW-yr estimated by the PJM consultant. Therefore, the cost of transmission from PJM with firm generating capacity (e.g., option AC Line – PJM) priced at $72/kW-yr may be optimistic and the cost of this option may be closer to the cost of

[41] Strategic Energy Services, Inc., "PJM CONE (cost of new entry) CT Revenue Requirements," February 4, 2005 reconciliation document.
[42] Levitan & Associates, Inc., "ICAP Demand Curve – Capital Cost Details and Update, September 1, 2004 Letter from Seth Parker to John W. Charleton of the NYISO

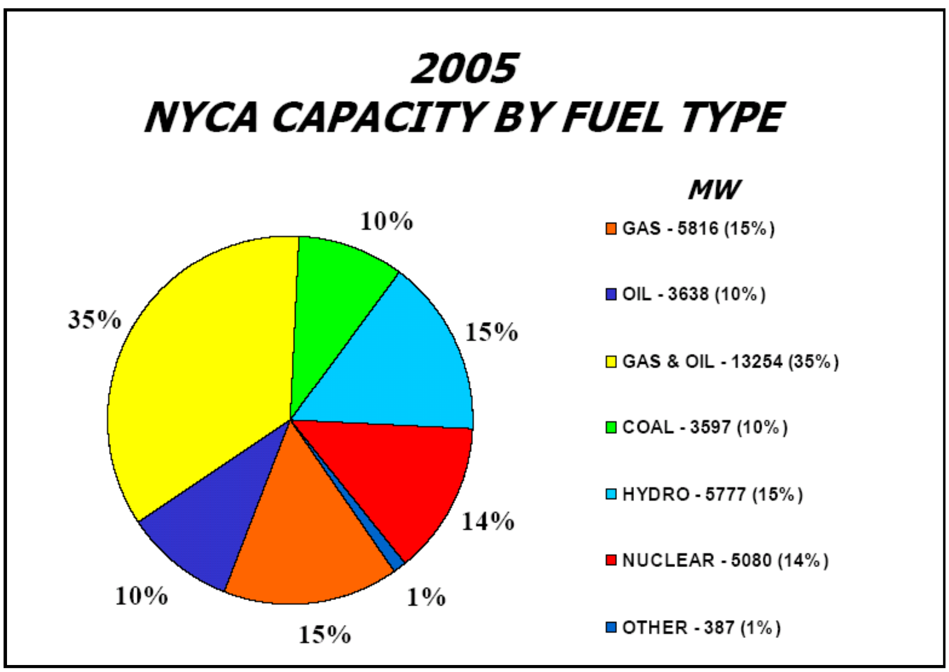
building new out-of-City generation in New Jersey with a radial transmission tie into New York City (e.g. option CCGT + AC).

Effective DSM energy efficiency options may be limited and may not yield load reduction levels comparable to new generation and transmission resources. In addition, the future incremental costs and benefits of energy efficiency measures will be altered by marketplace energy efficiency gains due to changes in consumer behavior and tighter energy efficiency standards that may be adopted. The SRAS analysis shows except for commercial lighting, DSM energy efficiency measures (i.e., the motors, commercial and residential HVAC and residential lighting options in Figure 22) may be attractive without incentives and therefore should occur naturally. To the extent these DSM energy efficiency options should be occurring but are not, tighter energy efficiency standards and building codes would ensure the broadest, most cost-effective, most equitable and most permanent implementation of DSM.

5.4 **Fuel Diversity**

Figures 23 and 24 show that the electric generating capacity in both New York State and New Jersey are predominantly oil and gas fired units. In New York State, 60% of the electric generating capacity is gas and/or oil versus 62% in New Jersey. In comparison, 100% of the electric generating capacity is gas and/or oil in New York City.

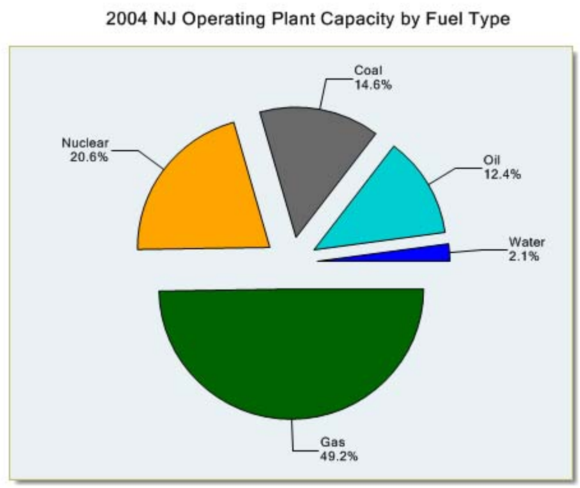
Figure 23. New York State Capacity Mix (as of April 2005)



Source: NYISO report, “2005 Load & Capacity Data”

Figure 24. New Jersey Capacity Mix (2004)

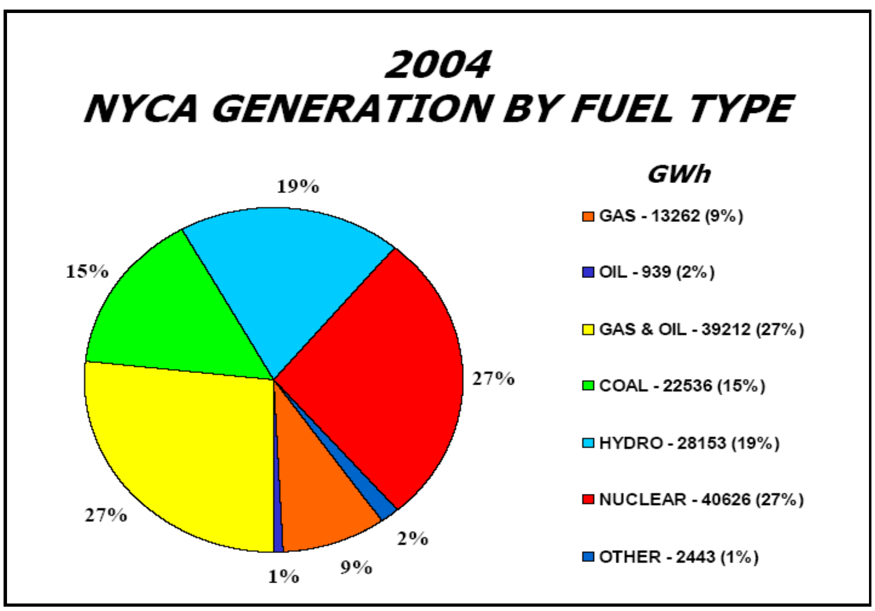
Fuel Type	Capacity (MW)
Gas	9,590
Nuclear	4,017
Coal	2,839
Oil	2,416
Water	414
Waste	188
Other Nonrenewable	24
Total	19,488



Source: SNL Financials Data, News and Analytics

Figures 25 and 26 show the 2004 electric generation mix capacity in New York State and New Jersey, respectively. A comparison of the electric generation mix shows that New York State has greater fuel diversity than New Jersey. In New York State, 38% of the electric generation in 2004 was produced using gas-fired and/or oil-fired units (see Figure 25) with the rest being primarily nuclear, hydro and coal. In New Jersey, 26% of the electric generation is gas-fired (see Figure 26), with the remainder predominantly nuclear and coal.

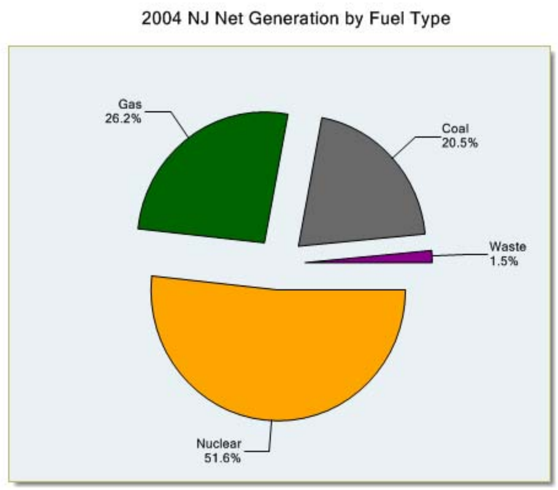
Figure 25. New York State Generation Mix (2004)



Source: NYISO report, “2005 Load & Capacity Data”

Figure 26. New Jersey Generation Mix (2004)

Fuel Type	Generation (GWh)
Nuclear	27,082
Gas	13,747
Coal	10,764
Waste	778
Oil	116
Other Nonrenewable	0
Water	(144)
Total	52,343



Source: SNL Financials Data, News and Analytics

Figure 27. Comparison of Capacity Factors

2004 Average Annual Capacity Factors		
	New York State	New Jersey
Gas/Oil	27%	13%
Hydro	55%	-
Coal	71%	43%
Nuclear	91%	77%

Figure 27 shows that the coal and nuclear generating units in New York State are base loaded, whereas gas-fired and oil-fired generating units are load following and/or to meet peak load. In New Jersey, based on the average capacity factors, coal generating units on average appear to be load following and gas and oil generating units operated as peaking facilities. This suggests that in New York State, gas and/or oil would be predominantly on the margin for almost all hours in the year and in New Jersey, coal could be on the margin during the off-peak hours with the rest of the hours predominantly gas and/or oil on the margin. This is corroborated by Cambridge Energy Research Associates, Inc. (CERA).[43] Therefore, new transmission to New Jersey would provide New York City with some fuel diversity benefit from accessing off-peak coal generation, but New York City would remain predominantly dependent on gas-fired and/or oil-fired electric generation during the on-peak hours.

[43] Cambridge Energy Research Associates. "Company Structure Reflecting the Hybrid Industry Landscape." North American Power Watch: Spring 2004.

5.5 **Adequacy of Fuel Supplies**

As shown in Figure 23, 35% of NYCA's generating capacity is dual-fueled, with the capability to use either gas or oil for electric generation. However, in New York City, about two-thirds of the electric generating capacity in New York City is dual-fueled. The dual-fueled capability provides the in-City generators with operational flexibility, reduces the reliability requirements on the gas delivery system, and enhances the reliability of the electric system. The gas delivery system in New York City has sufficient capability to support the existing electric capacity. While new electric generation coming on line uses gas, these facilities are expected to displace generation from existing facilities and will use 30% less fuel to produce the same amount of electric energy. The new gas-fired electric generation will have oil backup capability, but environmental restrictions on these new generating units will limit their oil burn capability to 30 days per year. Maintaining at least the existing level of dual-fueled electric capacity is essential to ensure future reliability and adequacy of fuel supplies for electric generation.

Certain demand side resources, like energy efficiency measures, would enhance fuel security by extending the date when new gas infrastructure would be needed. However, if enough demand resources like gas-fired distributed generation (which generally is not as efficient as a new centralized power plant) were to come on line to cause retirement of a dual-fueled generating unit without reducing the need for gas, then reliability would have been reduced.

5.6 **City Land Use Limitations**

Siting power plants, transmission lines, and gas pipelines is often difficult in urban centers, especially large urban areas like New York City, which has a high population density and land use constraints. Furthermore, the constraints that make siting difficult in New York City tend to spill over to the immediate areas outside the City, i.e., the New York Metropolitan Area.

Local communities always have concerns about the effects of energy development on land use, aesthetics, noise and air quality. It would be a difficult proposition to make to the local communities if the energy infrastructure to be built does not benefit them, such as running new transmission lines through the area or building power plants in the area for someone else's benefit.

Building on existing power plant sites would have the least incremental impact on land use, aesthetics and noise. Existing power plant sites are already part of the City's landscape and are attractive for siting power plants due to the presence of industrial zoned sites, gas pipelines and transmission facilities from earlier power plants. As the City continues to grow and considers properties for a range of economic and recreational activities, it should not lose sight of the need for energy infrastructure to support the City's economic growth.

5.7 Environmental and Health Issues

The varieties of fuels used to generate electricity all have some impact on the environment. For example, fossil fuel power plants release air pollutants. Pollutants from power plants include sulfur dioxide (SO_2), which can cause acid rain downwind from the power plants and nitrogen oxides (NO_x), which can lead to the formation of smog.

The new power plants that came online in New York City since the start of the NYISO in November 1999 all use natural gas (which is the cleanest of all the fossil fuels) as their primary fuel, have backend pollution controls and are more efficient than existing power plants. While environmental standards (e.g., SO_2 and NO_x limits) for large centralized power plants will become more restrictive over the next 10 years, environmental standards are more lax or non-existent for the small DG units. A recent study by the University of California Energy Institute[44] has revealed that the fraction of pollutant mass emitted that is inhaled by the downwind, exposed population can be more than an order of magnitude greater for DG technologies than for large, central-station power plants in California. An equitable application of environmental standards across the various supply options would eliminate unwarranted bias against cleaner supply options.

5.8 Homeland Security Needs and System Security Concerns

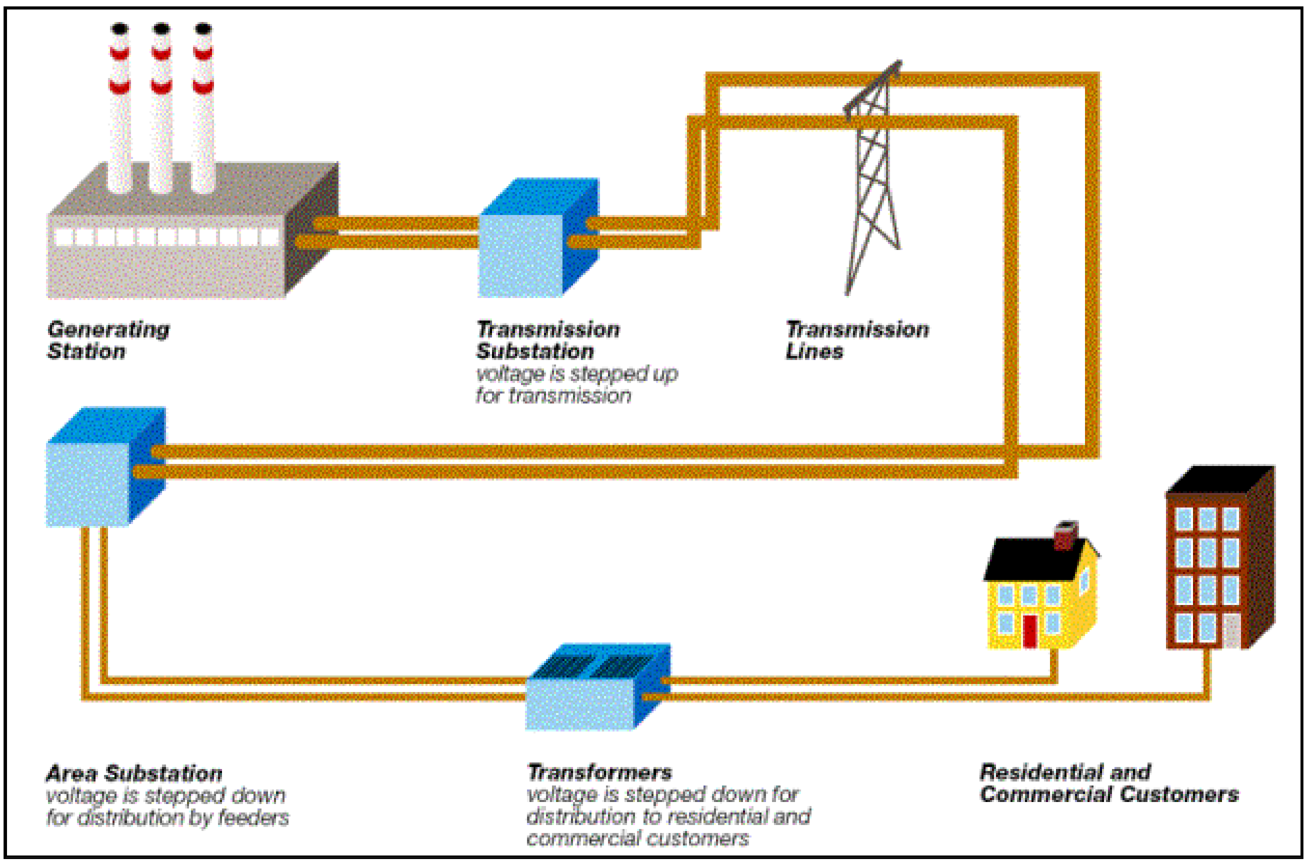
New York City, which has a peak load of more than 11,400 MW (in 2005), relies on a mix of in-City generation burning mostly natural gas and the import of generation from outside the City over the thirteen transmission cables into New York City. All thirteen transmission cables are buried, consisting of three from New Jersey, eight from Westchester and two from Long Island. Total nominal import capability over these transmission cables into New York City is currently 5,000 MW and thermally limited. Because these transmission cables are underground, they are less susceptible to terrorist attacks than are the overhead transmission lines upstream from these underground transmission cables.

<u>Electric Transmission</u>:
Figure 28 shows the conceptual arrangement of the electric system, consisting of generation, transmission and distribution. The electric

[44] Garvin A. Hath, Patrick W. Granvold, Abigail S. Hoats, William W. Nazaroff, "Quantifying the Air Pollution Exposure Consequences of Distributed Electricity Generation", University of California Energy Institute, Energy Development and Technology (EDT) Working Paper EDT-005R, November 2005

transmission system generally consists of the following elements: step-up transformers, transmission line, the transmission towers and the step-down transformers. The transmission system starts from the step-up transformers (housed in transmission substations) to boost the voltage from generators for delivery over transmission lines, the transmission lines themselves, transmission towers with either single or multiple circuits, and step-down transformers (housed in area substations) to reduce the voltage for delivery to the distribution system. Burying the transmission lines would make only the lines themselves less susceptible to an attack. Common mode failures, such the loss of a transmission tower with multiple circuits, present the greatest risk with a failure of an element (in this case, the transmission tower). The potential impact of element failures is minimized through designing the system to operate reliably under contingency conditions such as loss of the single or multiple largest element(s) on the system.

Figure 28. Electric System



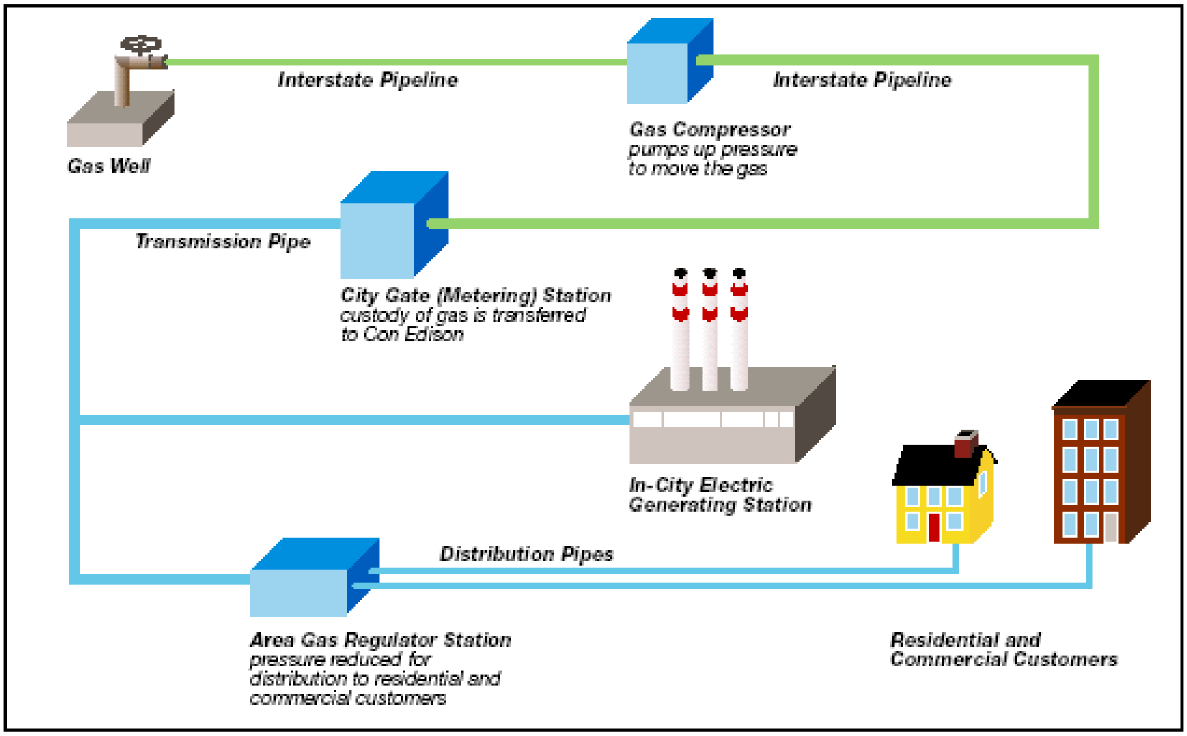
Bulk power failures usually result from failing to isolate the cascading effects from an initial point of disturbance on the system. The reasons for failure to isolate a system disturbance may include protective devices not tripping within the required time and sequence according to design, problems with the communication or information systems, and human error. A coordinated attack on multiple substations would definitely stress the system, increasing the risk of system failure. The time to restore service to a substation after an attack could be dependent on the availability of enough spare equipment, especially transformers with long-lead time for delivery.

In-City Generation:
The in-City generating plants are dispersed over the boroughs of Manhattan, Queens, Staten Island and Brooklyn. However, because almost all the in-City generating plants use natural gas as the primary fuel, they are dependent on the gas pipelines into New York City. Currently there are two groups of gas pipelines feeding New York City, with one group consisting of four pipelines bringing natural gas from the Gulf Coast region and the other one being the Iroquois Gas Transmission system that receives western Canadian gas from the Trans-Canada pipeline in Ontario.[45] With access to five gas pipelines, generators in New York City are afforded a diverse supply of natural gas.

Gas Delivery System:
Figure 29 shows the conceptual arrangement of the gas delivery system, consisting of interstate pipeline from the gas well (predominantly in the Gulf Coast region or western Canada) to a city gate metering station, gas transmission to the area gas regulator station and distribution. Interstate gas pipelines are even longer than electric transmission lines and could also be vulnerable to attacks. The pipelines themselves are buried, but they depend on compressor stations to keep the natural gas moving. However, unlike the electric transmission system, natural gas pipelines are less complex and typically easier to restore after a major loss.

[45] Of the four pipelines from the Gulf Coast region, only Duke's Texas Eastern and Williams' Transco pipelines are directly connected to New York City Gate Stations. The other two, Duke's Algonquin and El Paso's Tennessee pipelines are connected to the Con Edison Gas System in Westchester, which is integrated with the rest of the Con Edison Gas System in New York City as well as with the KeySpan Gas System in New York City.

Figure 29. Gas Delivery System



Considerations for Electric Reliability:
Homeland and system security concerns alone would favor smaller and more disperse generation that is closer to the load, and resources that do not require a fuel source, such as solar photovoltaic and energy efficiency demand side measures. However, these resources are currently incapable of providing the majority of the capacity needs in New York City.

Homeland and system security concerns would also give rise to consideration for dual-fuel capability and back-up fuel for electric generation and back-up generation or energy storage on site for vital services.

5.9 Market Power Considerations

The NYISO uses market monitoring and market mitigation measures to ensure that the wholesale electricity markets in New York will produce prices that are not affected by market power.[46] In the capacity market, the ICAP demand curve reduces the incentive for generators to withhold capacity. Also, the bid caps on Con Edison's divested in-City generation, as well as the requirement for the divested in-City generation plants to offer all their capacity into the NYISO's ICAP auctions, limit the concerns

[46] New York ISO 2004 State of the Market Report, Potomac Economics, LTD., July 2005.

for potential market power abuse in the in-City capacity market.[47] New entry into the New York City market such as generation projects like Astoria Energy, additional transmission or additional demand response would promote greater competition and further minimize the potential for market power.

5.10 DSM Uncertainties

There are uncertainties regarding how much DSM will occur naturally as a result of many factors, including energy prices, more stringent equipment standards, building codes, and changing consumer behavior.

As more DSM occurs naturally and becomes more prevalent in the marketplace, the incremental cost to encourage the next level of DSM will become greater unless technological gains in end-use energy efficiency keep pace. Also, the incremental benefit of a funded DSM measure over what would occur naturally would be reduced or lost if during the life of the DSM measure more stringent equipment standards and building codes were adopted, which would embed the benefits already paid for in funding the DSM measure.

The incremental benefit of a funded DSM measure could also be reduced or lost if the DSM user decides it could afford to use more electricity or replace the DSM measure prematurely, i.e., before its end of life.

Hence, despite its many benefits, the achievability of DSM must be a consideration for the SRAS. For example, according to its most recent report,[48] the amount of peak MW savings achieved by NYSERDA programs declined from 2003 to 2004 (from 880 MW to 860 MW).

6.0 Preliminary Review of Options for Securing New Resources

6.1 Market Solutions

6.1.1 NYISO Comprehensive Reliability Planning Process

Figure 30 diagrams the NYISO reliability planning process. As the first step in the CRPP, the NYISO prepares an RNA to determine if there are reliability needs with respect to either resource adequacy or transmission reliability. After the approval of the RNA by the NYISO Board, the NYISO will issue the RNA to the marketplace and request market-based solutions to respond to the reliability needs identified in the RNA.

[47] The Con Edison divested generation plants are KeySpan's Ravenswood 1, 2, 3 units and the Ravenswood gas turbines, Reliant Energy's Astoria 3, 4, 5 units and the Narrows and Gowanus gas turbines, and NRG Energy's Arthur Kill 2 and 3 units and the Astoria gas turbines.

[48] NYSERDA, "New York Energy Smart Program Evaluation and Status Report," May 2005

Once reliability needs are identified, the responsible transmission owners are obligated to propose regulated backstop solutions to meet the identified needs if, and only if, timely, viable market-based solutions do not materialize. The NYISO evaluates the proposed regulated backstop to ensure that it satisfies the identified reliability need. Either the market-based or the regulated solutions could be proposed as transmission, generation, and/or demand response projects. The NYISO also evaluates each proposed market-based solution to determine whether it is sufficient to meet an identified reliability need in a timely manner. The NYISO does not choose among the market solutions if more than one satisfies the same need.

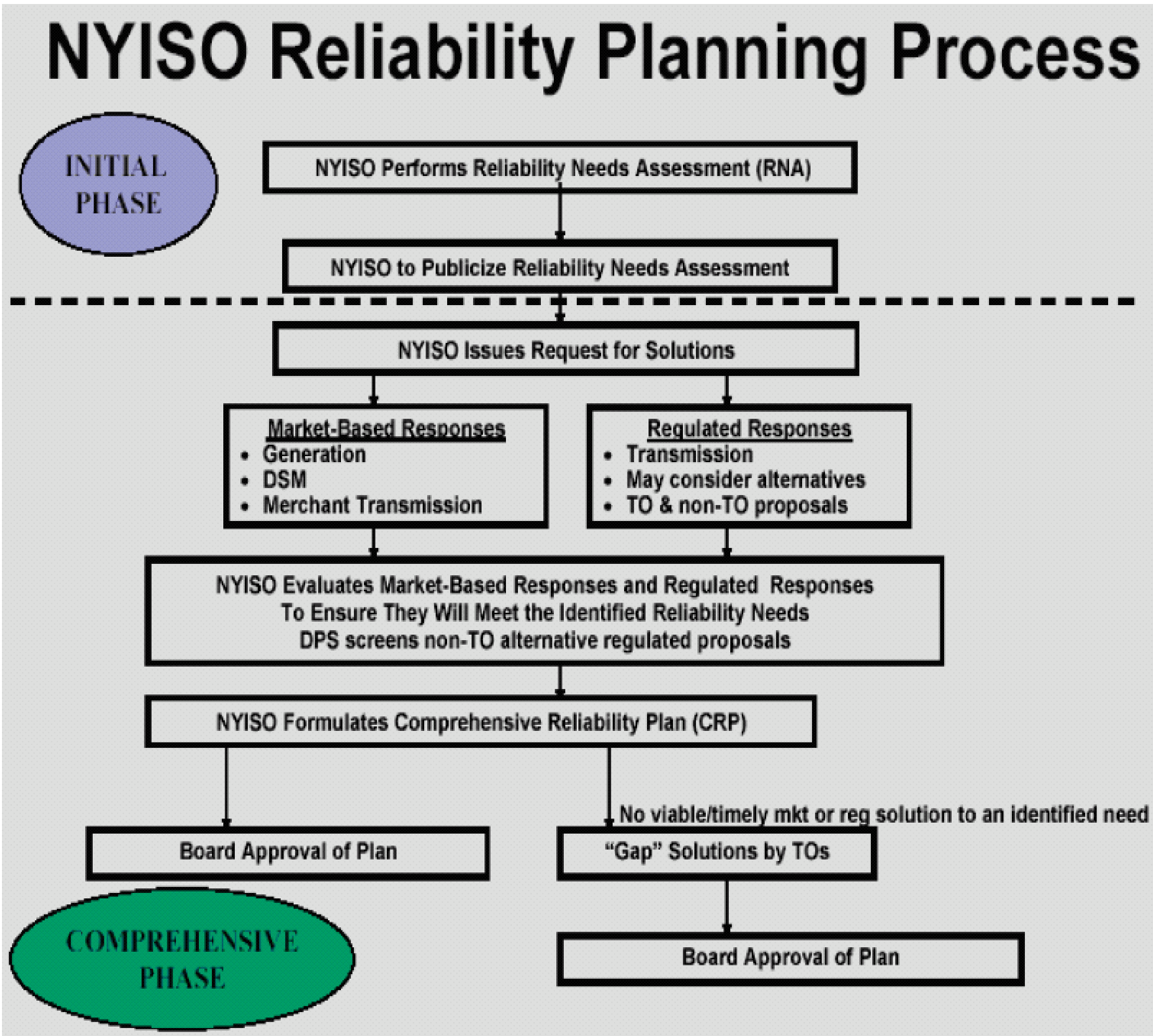
Following its evaluation of all proposed solutions, the NYISO will prepare its Comprehensive Reliability Plan, which will identify all proposed solutions that have been found to meet the identified reliability needs. Once the marketplace is given ample opportunity to propose solutions, if there is no viable market based solution to meet an identified reliability need, the NYISO will solicit alternative regulated responses and developers will then have the ability to submit alternate regulated solutions for evaluation. The NYISO has the obligation to monitor the continued viability of proposed projects to meet identified needs and to report on its findings in subsequent plans.

If, and only if, the marketplace does not respond with viable market-based proposals to meet the identified reliability needs, the NYISO will request the appropriate transmission owner or owners to proceed with the development of a backstop solution. In the event that it becomes apparent that there is an immediate threat to reliability, and neither the proposed market-based solutions nor the proposed regulated backstop solutions can satisfy the reliability need in a timely manner, the NYISO will request the appropriate transmission owner to develop a “gap solution” outside the normal planning cycle, and so note in the next Comprehensive Reliability Plan. Gap solutions are intended to be temporary in nature so as not to interfere with any pending market-based project. Once the NYISO determines that a gap solution is necessary, the CRPP allows any party to submit a gap solution for consideration.

The CRPP also address the issues of cost allocation and cost recovery associated with regulated backstop solutions. The approved NYISO Tariff contains a set of principles for cost allocation based upon the concept that beneficiaries should pay. The NYISO is presently engaged in a stakeholder process to develop the implementation procedures for cost allocation and cost recovery of regulated backstop projects.

The CRPP satisfies the requirement that the SRAS make preliminary recommendations concerning the facilitation of the competitive development of generation, transmission and DSM.

Figure 30. NYISO CRPP



6.1.2 Load Serving Entities (LSEs) / Large Customers to Contract for New Resources

LSEs or large customers who are looking for long-term supplies and firm prices could be candidates to provide power purchase agreements (PPA) to developers to help finance new generation and/or transmission. For example, NYPA as an LSE has issued an RFP for 500 MW of new in-City capacity. These LSEs would probably have financially healthy balance sheets and steady or growing customer bases. However, customers do not typically contract directly with developers today, but should developers hold open seasons to auction capacity tranches, enough large customers and others could participate to provide the financial commitment developers needed to help finance the new resource. With respect to DSM, LSEs or large customers could also consider DSM for reasons that include energy bill reductions.

6.1.3 **Merchant Projects**

Merchant developers with strong balance sheets do not necessarily need a PPA to build new generation, as demonstrated by KeySpan when it constructed and placed in service its 250 MW Ravenswood Unit 4 in 2004. However, in most cases today, merchant developers must have a PPA in order to obtain financing. With respect to merchant transmission, the experience to date shows that a merchant transmission developer would need a contract from someone to buy the transmission capacity in order to build, as demonstrated by the 330 MW Cross Sound Cable Project from Connecticut to Long Island and the 660 MW Neptune Project from New Jersey to Long Island.

The success of these projects, coupled with the cancellation of the 1,000 MW Empire Connection Project, demonstrate that merchant transmission projects may have to be on the scale of the Neptune Project or less in order to be viable. Concerns with large projects such as the Empire Connection Project include potentially becoming the largest contingency on the system.

6.2 **Regulated Backstop Solutions**

As a transmission owner, Con Edison will work within the framework of the NYISO CRPP to identify regulated backstop solutions for implementation if there is no market based solution. In the case of regulated backstop solutions involving the service areas of other transmission owners, to the extent there would be an impact on Con Edison's service territory, Con Edison will work together with those other transmission owners to develop the regulated backstop solutions.

6.3 **675 MW DSM Initiative**

In Con Edison's 2005 electric rate agreement in Case 04-E-0572, a DSM initiative was established with the goal to enroll up to 675 MW of DSM by March 31, 2008. At this time, it is uncertain how much DSM will be achieved by this initiative and when it would become effective. Figure 31 shows the in-City resource situation without any contribution from the 675 MW DSM initiative and also three potential scenarios of varying DSM levels (25%, 50% and 75%) that could be achieved from the initiative, assuming a 5-year ramping rate starting in 2008. This shows that if 75% were achieved, the date when the City would need new generation or transmission could be deferred from 2012 to as late as 2014.

Figure 31. Potential Impact of 675 MW DSM Initiative on New York City Needs

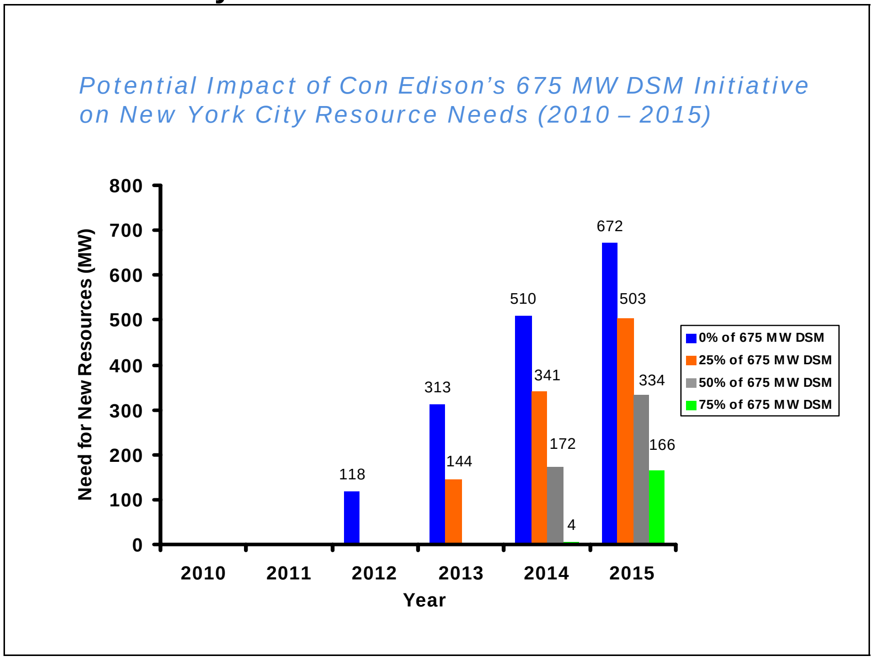
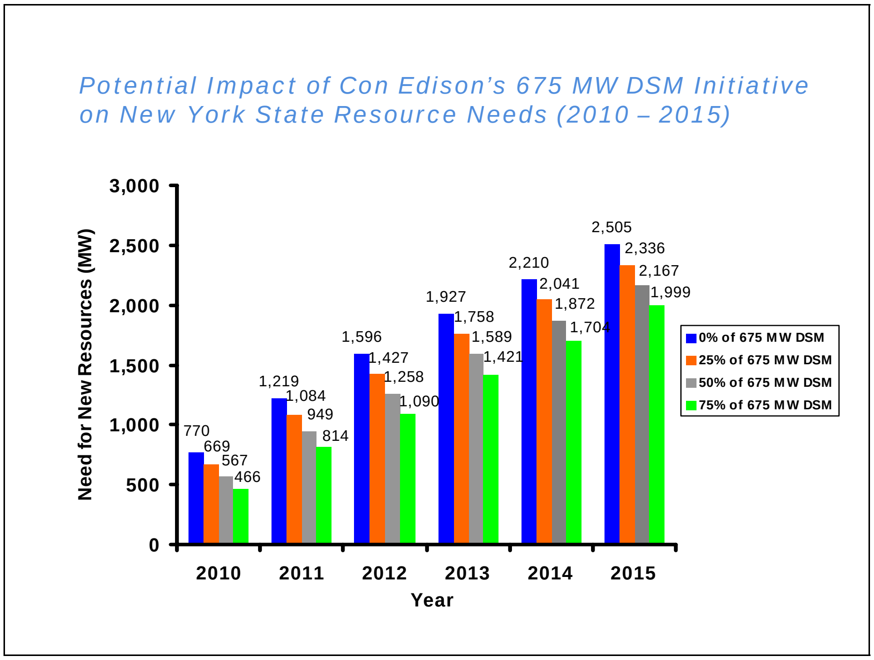


Figure 32 shows the corresponding potential impact on the New York State resource situation. This shows that the 675 MW DSM initiative would have no impact on when new resources are needed in New York State, but the initiative could affect New York City need. .

Figure 32. Potential Impact of 675 MW DSM Initiative on New York State Needs



7.0 Uncertainty Analysis

7.1 Discussion of Factors that Would Influence Results and Options

The factors that influence the resource adequacy analysis in the Con Edison SRAS are also present in the reliability studies the NYSRC and NYISO conduct every year. The NYSRC and the NYISO each year perform studies to set the statewide installed capacity requirements and the locational capacity requirements, respectively, for the next capability year. The studies are based on conducting many reliability simulations of the New York Control Area and other interconnected control areas in the Northeast using the GE MARS model and input assumptions about future load and system performance for the next capability year. The NYSRC and the NYISO acknowledge the inherent uncertainties in reliability simulations, which include the following:

- The amount of interconnection support during emergencies from other interconnected control areas such as PJM and ISO-NE
- The load forecast uncertainty probability distributions used for the various zones in NYCA
- The use of historical forced and partial outage data to forecast future availability of generating units and the transmission system
- Potential unscheduled generating unit and transmission system maintenance
- Potential delays in planned resources

Multi-year reliability studies such as the NYISO RNA and the Con Edison SRAS have greater uncertainties than annual reliability studies such as the NYSRC statewide installed capacity requirements study and the NYISO locational capacity requirements study. The NYISO RNA and the Con Edison SRAS, which look out ten years, have the same uncertainties as annual reliability studies looking out only one year, except those uncertainties would be compounded ten times.

With respect to the cost-benefit analysis of resource options, the costs were derived as averages of cost information from multiple sources, and therefore should be viewed as generic in the sense that they are not site-specific or application-specific. The capacity cost of each resource option, which is the total cost net of energy benefits, is a function of many factors that have uncertainties over the life of the resource option. These factors with uncertainties include the following:

- Varying fuel prices over time
- Varying electric energy prices (or market heat rates) over time
- Amount of capacity utilization
- When during the day and season the capacity is utilized
- Capital and O&M costs of resource options

- Future technological advances in both supply-side and demand-side resources

The reliability benefit of each resource option is subject to all the uncertainties of the resource adequacy analysis discussed above.

7.2 Identification and Discussion of Signposts to Monitor Uncertainties

The economy is one signpost that should be monitored. The economy drives load, fuel prices, and electric energy prices. A weaker than expected economy would delay the date when new resources may be needed and also reduces the demand for fuel, resulting in lower fuel prices. On the other hand, a stronger than expected economy would accelerate the date when new resources may be needed and also increase demand for fuel, resulting in higher fuel prices.

Fuel prices greatly impact the economics of resource options. For example, demand-side resources that focus on end-use energy efficiency would be more economical when fuel prices are high. Other signposts besides the economy, which help indicate the direction of fuel prices, include development of liquefied natural gas (LNG) facilities and imposition of more stringent emission standards. Faster development of LNG may soften fuel prices, making resource options such as demand-side resources less attractive. However, more stringent emission standards would have the opposite effect.

The unevenness in technological advances in generation, transmission, and end-use resource options would affect their economics relative to each other. Simple cycle gas turbines and combined cycle turbines are relatively mature technologies. On the other hand, less traditional and more costly resources like photovoltaics and molten carbonate fuel cells are still developing technologies and have more room to advance.

Governmental programs may favor resource options that are not initially cost-competitive, but which provide a social benefit. In these cases, higher costs may be addressed through incentives such as tax credits to promote a selected resource option or through levying disincentives on other resource options.

8.0 Conclusions and Recommendations

The Con Edison SRAS shows different resource needs than the NYISO RNA. While some of the difference can be attributed to the base case assumptions, most of the difference is due to the criteria used to identify where resources are needed. The base case assumption differences are that the Con Edison SRAS assumes: (1) Poletti retirement in 2010 instead of 2008, (2) the Transmission

Project M29 to be in service, and (3) the Caithness Project to be built. The NYISO assumes these projects are potential solutions to the need that results from their absence.

The Con Edison SRAS uses the conventional method of converting the 0.1 day / year LOLE criterion to a set of statewide installed capacity requirements and the New York City and Long Island locational capacity requirements to identify how much and where new resources are needed. On the other hand, the NYISO RNA identifies the zone with the highest zonal LOLE to be the zone where new resources are to be located when the NYCA LOLE exceeds 0.1 day / year. However, the RNA also recognizes other solutions may exist. The NYSRC who is the reliability council in the State (and the NYISO is required to implement the NYSRC reliability rules) does not have any reliability rules that require new resources to be located in the zone with the highest zonal LOLE when the State needs new resources. Requiring new resources only to be added to the zone with the highest LOLE ignores the possibility that the import capability into that zone may be underutilized due to lack of supply limiting the import capability. Therefore, it is recommended that the NYISO should adopt a more conventional method consistent with existing reliability rules and practices when identifying where new resources are needed.

The Con Edison SRAS shows that 770 MW of new resources would be needed north of New York City (e.g., Lower Hudson Valley) by 2010, quickly rising to about 1,220 MW by 2011, and remaining relatively stable at about 1,300 MW on average through 2015.

Load growth in the Lower Hudson Valley is expected to be almost 1,200 MW from 2005 level over the 2006 – 2015 period, which would account for essentially all of the 1,300 MW the capacity needed north of New York City by 2015. Therefore, placing new generation in the Lower Hudson Valley would not only meet load growth in that area, it would also provide critical reactive power in the Lower Hudson Valley, and support transfer capability to New York City and Long Island.

New York City and Long Island do not need new resources until 2012. Contributions from Con Edison's 675 MW DSM Initiative could defer the New York City need date past 2012 to possibly as late as 2014 if there is a 75% or higher success rate.

The resource options analysis does not show any single resource option to be the solution to meet all resource needs. Identifying the needs and allowing the competitive market the opportunity to meet those needs is expected to result in a variety of solutions that would be more robust than a single backstop solution would provide. Con Edison has taken an active role in the development of the NYISO CRPP to foster competitive market opportunities for resource supplies and is optimistic that the NYISO planning process will lead to the development of proposed projects that will address resource needs. Both market solutions and backstop solutions will be proposed and evaluated within the framework of the NYISO CRPP.[49]

[49] The CRPP satisfies the requirement that SRAS make preliminary recommendations concerning the facilitation of the competitive development of generation, transmission and DSM.

APPENDIX A: SRAS Requirements from Electric Rate Agreement
(Section K, pages 72-76 of the December 2, 2004 Joint Proposal in Case 04-E-0572)

K. System Reliability Assurance

1. Scope of Study

In coordination with the ongoing Comprehensive Reliability Planning Process for Reliability Needs of the NYISO and such modifications thereto as may be directed by the FERC, and in order to assure the long-term reliability of the Company's bulk power system, particularly in New York City, the Company will develop a Study ("Study") that examines the supply and demand side resource options that will be needed to adequately meet system demand in the next 10 years (the "Study Period"). While that time frame is beyond the duration of the Electric Rate Plan, the design, approval, and construction process for new or repowered facilities necessitates analysis and planning well in advance of system needs. The Study will acknowledge New York's competitive electric market and any findings will be consistent with a competitive environment.

The Study will examine: (i) the NYISO's current 80% minimum in-City locational reliability requirement, and the effects of any revisions thereto as may be made prior to completion of the Study or that Con Edison may reasonably anticipate in the future due to load growth or other changing circumstances during the Study Period; and (ii) the feasibility of both new and repowered generation plants, demand-side resources, and additional bulk transmission lines as a means of meeting the expected load growth, accommodating retirements and enhancing competition in the Company service territory in the Study Period. The Study will review and make preliminary recommendations concerning potential means of facilitating the competitive development of generation, transmission, and demand-side resources needed for system reliability, including, but not limited to, the use of auctions and long-term power purchase agreements.

The Study should give appropriate consideration to cost-benefit calculations and the reliability impact of each potential option, as well as such factors as the adequacy of fuel supplies, the desire for diversity of both fuel supplies and generation resources, Homeland Security needs and system security concerns, City land use limitations, and environmental and health issues. The Study should also be consistent with the Commission's Statement of Policy of August 25, 2004 in Case 00-M-0504.

2. <u>Jurisdictional Setting</u>

The parties hereto recognize that the NYISO has filed with the FERC an Agreement between the NYISO and the New York Transmission Owners on the Comprehensive Reliability Planning Process, and that the Company will have rights and obligations as set forth in that Agreement if it is approved by the FERC and executed by the Company. The parties also recognize that the Company has obligations and responsibilities as an electric corporation subject to the Commission's jurisdiction.

3. <u>Preparation and Input</u>

The Company may contract with one or more independent consultants to perform the Study, or portions thereof, and defer the reasonably incurred costs of such consultant(s) for later recovery.

The scope of the Study will be developed in cooperation with Staff, NYCEDC, COW, and Signatory Parties (including their principals and members) to this Proposal. In addition, Study input should be sought from the NYISO, the New York State Reliability Council, and potentially interested governmental and regulatory entities, such as the federal Departments of Homeland Security and Energy, FERC, NYSDEC, and NYSERDA.

To avoid duplication of effort, the Study will exclude consideration of the subjects addressed in the steam production study discussed in the Gas/Steam Rate Order.

4. Timing

The Study process will be commenced within 60 days of the date of the Commission Order approving or adopting this Proposal, and the Company will use best efforts to issue the Study by December 31, 2005. If the Study is not issued by December 31, 2005, the Company will update Staff, NYCEDC, COW, and the Signatory Parties as to its expected completion date.

The Study, when completed, will be made available to Staff, NYCEDC, COW, and other interested parties. To the extent the Study contains confidential cost projections or cost data or security sensitive information, those sections of the Study will be segregated and treated as confidential information, in accordance with the Commission's trade secret regulations, and will not be disseminated to parties other than Staff.

5. Interplay of Con Edison's Obligations

If the NYISO, as a result of the Comprehensive Reliability Planning Process, identifies a reliability need within the Company's bulk power system within the Study Period, the Company will identify for the NYISO and the

Commission proposed backstop solutions, which should be based on the Study findings if such findings are available at the time the Company must identify its potential backstop solutions. One or more of the proposed backstop solutions will be implemented in the absence of a market response to the NYISO's identified need, in accordance with the NYISO process.

If the NYISO Comprehensive Reliability Planning Process is rejected by the FERC, is abandoned or terminated, or fails to produce annual "Reliability Needs Assessments" for the Company's service territory during the Electric Rate Plan, and instead the Company identifies a reliability need within the Company's bulk power system within the Study Period, and the Commission confirms that such need must be met, the Company will submit to the Commission, and other regulatory bodies, as appropriate, proposed backstop solutions for addressing the identified need, which should be based on the Study findings if such are available at the time the Company must identify its potential backstop solutions. One or more such solutions will be implemented in the absence of a market response to this identified need.

In either case, the procedure to be employed related to the implementation of the appropriate backstop solution(s) will involve a filing by the Company with the Commission that describes the backstop solution(s) chosen by the Company, including the rationale for its choice(s), the Company's proposal for implementing its solution(s), and any plan to solicit and consider offers or bids associated with the proposed solution(s). Interested parties will then be provided an opportunity to comment on the Company's filing.

APPENDIX B: Unified Methodology to Calculate IRM and LCRs

(Source: NYSRC's December 6, 2005 Draft Report, "New York Control Area Installed Capacity Requirements for the Period May 2006 Through April 2007"

In the past, the NYCA IRM has been calculated by starting with the current load forecast and generating capacity. Since NYCA has had excess capacity, the IRM to achieve an LOLE of one day in ten years (or 0.1 day / year) was determined by adding load to each of the zones in proportion to the Zone's peak load. If the locational capacity to peak load ratios for zones J and K at criteria were below the previous year's locational capacity requirements, they were adjusted to meet the locational requirements.

STEP 1. The unified methodology starts with the forecasted loads for each zone and NYCA, capacity is then removed from the zones west of the Central East interface that have capacity in excess of their peak loads until the targeted NYCA IRM is reached. The capacity is removed proportionally to the amount of excess capacity in each of the zones. (Various IRM values are chosen so a curve can be drawn.) This capacity is removed by adding negative perfect capacities to these zones. For calculation purposes, this perfect capacity is translated to real capacity using the average availability of the existing capacity in that zone.

STEP 2. Remove capacity from Zone J (in the same manner as above) and add an equivalent capacity spread among the identified zones above until 0.1 LOLE is reached. This perfect capacity is translated to real capacity using the availability of a new combined cycle unit.

STEP 3. Starting with the system in step 1, capacity is removed from Zone K in a similar manner.

STEP 4. Again starting with the system in step 1, capacity is removed simultaneously from Zones J and K in proportion to the capacity removed in steps 2 and 3 and an equivalent amount of capacity is added to the identified zones above until 0.1 LOLE is achieved.

STEP 5. This process is repeated with different IRM values so a curve can be drawn.

For each point on the curve, the minimum locational requirements for Zones J and K are identified.

APPENDIX C: MARS Database Benchmarking

Background

Con Edison's MARS database was used to calculate the LOEE for the sensitivity cases performed by GE of adding 500 MW of each of the resource options. Con Edison also conducted sensitivity cases to evaluate the reliability benefit of adding 250 MW instead of 500 MW of each resource option.

Most of the MARS input data used to build Con Edison's MARS database was available at the NYSRC web site. This database contains the information used in the NYSRC's 2005 IRM study and the NYISO RNA study, except for the following information that is considered by the NYISO to be proprietary:

- Unit and transmission availability. The unit availability information is composed of two sets of input data, the Transition Rate input table and Capacity State input table. With these two tables one can calculate the Effective Forced Outage Rate on Demand (EFORd) for each of the units in NYCA and the neighboring control areas. This information is not released by the NYISO even for previous years.

- Unit scheduled outages.

In addition, beginning this year (2005), the NYISO under nondisclosure agreement exchanged with the neighboring control areas MARS' input data regarding transmission topology, load profile, unit and transmission availability, and unit schedule outages. Because this information is also proprietary, they were not available to Con Edison to incorporate in its MARS database.

Therefore, Con Edison built the MARS database using the available input files from the NYSRC, internal information, and national averages for the excluded proprietary information. Then, Con Edison benchmarked the GE MARS database by comparing the MARS outputs such as the zonal LOLEs, the emergency assistance flows among zones, and the level of reliability of the neighboring control areas against the MARS outputs from GE who ran cases using the NYISO proprietary MARS database.

Description of Analyses

The benchmarking process involves an iterative approach of adjusting and re-adjusting the MARS input data to achieve MARS output that approximates the known MARS output corresponding to the NYISO proprietary MARS database. For example, Con Edison had to approximate the EFORd and maintenance schedules for generation assets in the New York Control Area (NYCA), with the actual information being proprietary. Also, almost all the information in the NYISO MARS database on the external control areas such as PJM and ISO-NE was propriety, and as such, Con Edison had to approximate it through the benchmarking process as well.

The following methodology consisting of two parts was used to approximate the excluded information:

Part A (Benchmarking isolated zonal reliability levels)

1. Set the EFORd of each NYCA generator and the outside world generator to the national average based on type, size, and installation date. Company owned generator EFORds are also set.

2. Adjust NYCA generator EFORds within the national average range to meet historical EFORd averages by zone and adjust neighboring control area generator EFORds to meet the control area average.

3. Run MARS simulation.

4. Compare LOLE results for each load zone in NYCA and the neighboring control areas for the baseline EFORd simulation with LOLE results from the simulation outputs from using the NYISO's MARS database.

5. Adjust to approximate base case results by making reasonable changes to the EFORds and maintenance schedules for NYCA generators.

6. Adjust to approximate base case results by making changes to reserve margins of neighboring pools.

7. Re-run MARS simulation, re-evaluate results. Repeat steps 4 through 7 until isolated results approximate the isolated results from the case GE ran using the NYISO proprietary MARS database.

Part B (Benchmarking the interconnected system)

1. Starting with the resulting MARS database from Part A, run the MARS simulation with NYCA now interconnected and compare the emergency assistance flows among the zones with NYISO's MARS database output. Re-arrange the maintenance schedule for the NYCA zones to correct NYCA internal flows and adjust the reserve margin and load profile of the neighboring control areas to correct emergency assistance from them to NYCA.

2. Because each of the neighboring control areas was represented as a single area (i.e., no transmission constraints within each neighboring control area) in Con Edison's database, loop flows through the neighboring control areas were a concern. Therefore, it was necessary to reduce export limits to restrict flows from the NYCA's west of Central East interface zones to the neighboring control areas and back to the NYCA's east of Central East interface zones to

eliminate the bypass around the UPNY/CONED and the Central East interfaces.

3. Repeat steps 1 and 2 until the interconnected NYCA results and flows approximate the interconnected results from the NYISO's base case simulation.

Results and Discussion

Figure C1 compares the Con Edison's benchmarked results against those from GE for years 2010 and 2015:

Figure C1. Con Edison's vs. GE's LOLE results

	Year 2010 LOLE Values (days/yr)		Year 2015 LOLE Values (days/yr)	
	Con Edison	GE	Con Edison	GE
Zone-A	0	0	0	0
Zone-B	0.016	0	0.024	0
Zone-C	0	0	0	0
Zone-D	0	0	0	0
Zone-E	0.01	0	0.02	0
Zone-F	0.001	0	0.004	0.002
Zone-G	0.037	0.009	0.91	0.283
Zone-H	0.005	0.004	0.033	0.013
Zone-I	0.116	0.132	1.604	1.989
Zone-J	0.131	0.1	1.322	1.451
Zone-K	0.069	0.07	0.909	1.406
NYCA	0.18	0.163	1.935	2.272

The above comparison shows that using Con Edison's benchmarked internal MARS database resulted in LOLE values similar to those using NYISO's MARS database with NYISO proprietary information. The two major differences of the final results are the LOLE of Zones B and G mostly due to differences in maintenance schedules and EFORds. In both cases the error is not greater than 30 minutes of loss of load on average per year for year 2010 and no more than 12 hours for year 2015.

The comparison is closest at the NYCA level and for year 2010. As a result, Con Edison's benchmarked internal MARS database was used primarily to evaluate the reliability impact on NYCA of adding resource options in year 2010 when resources are needed in the State.

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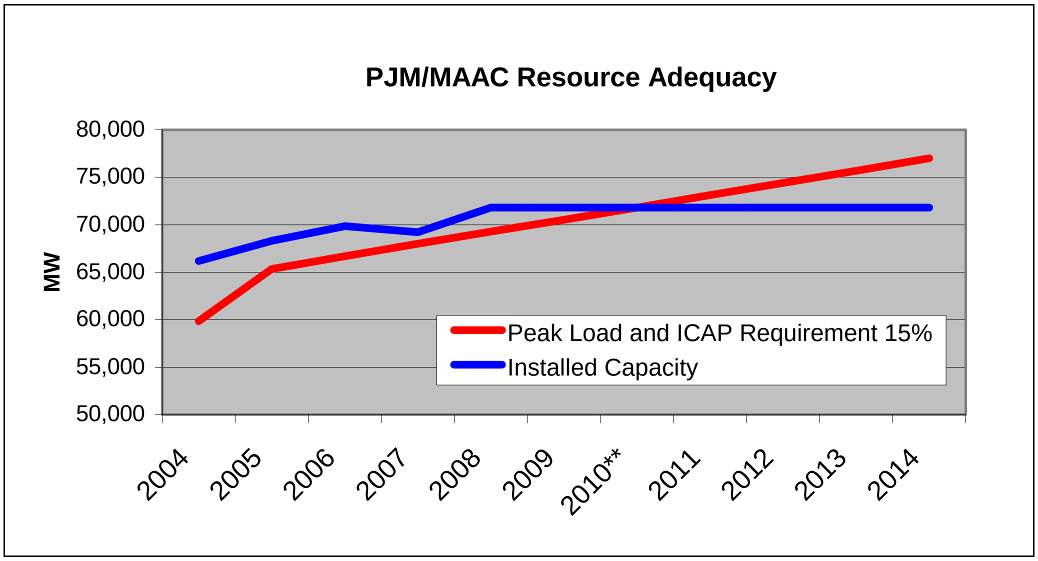
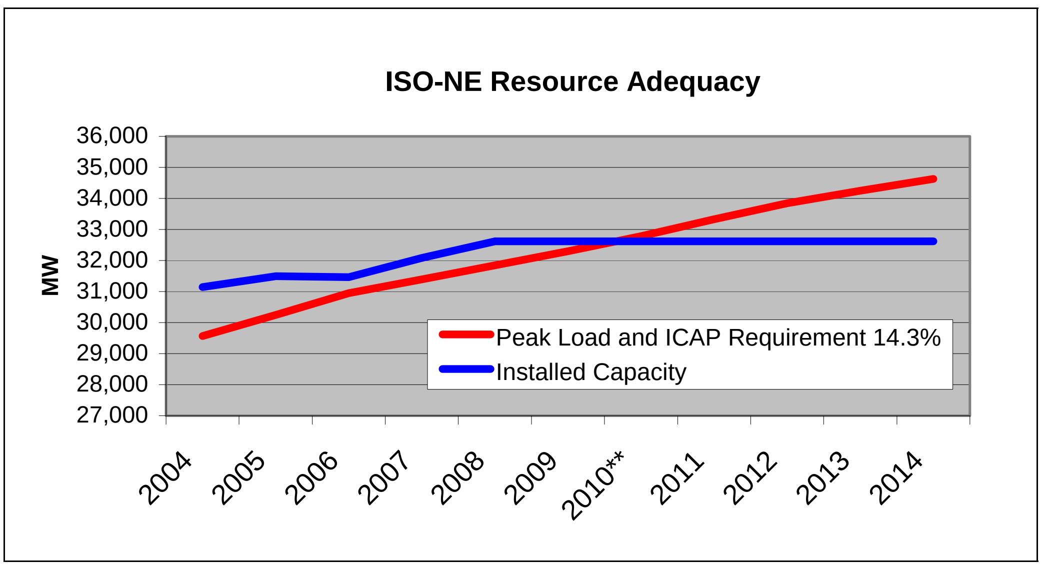
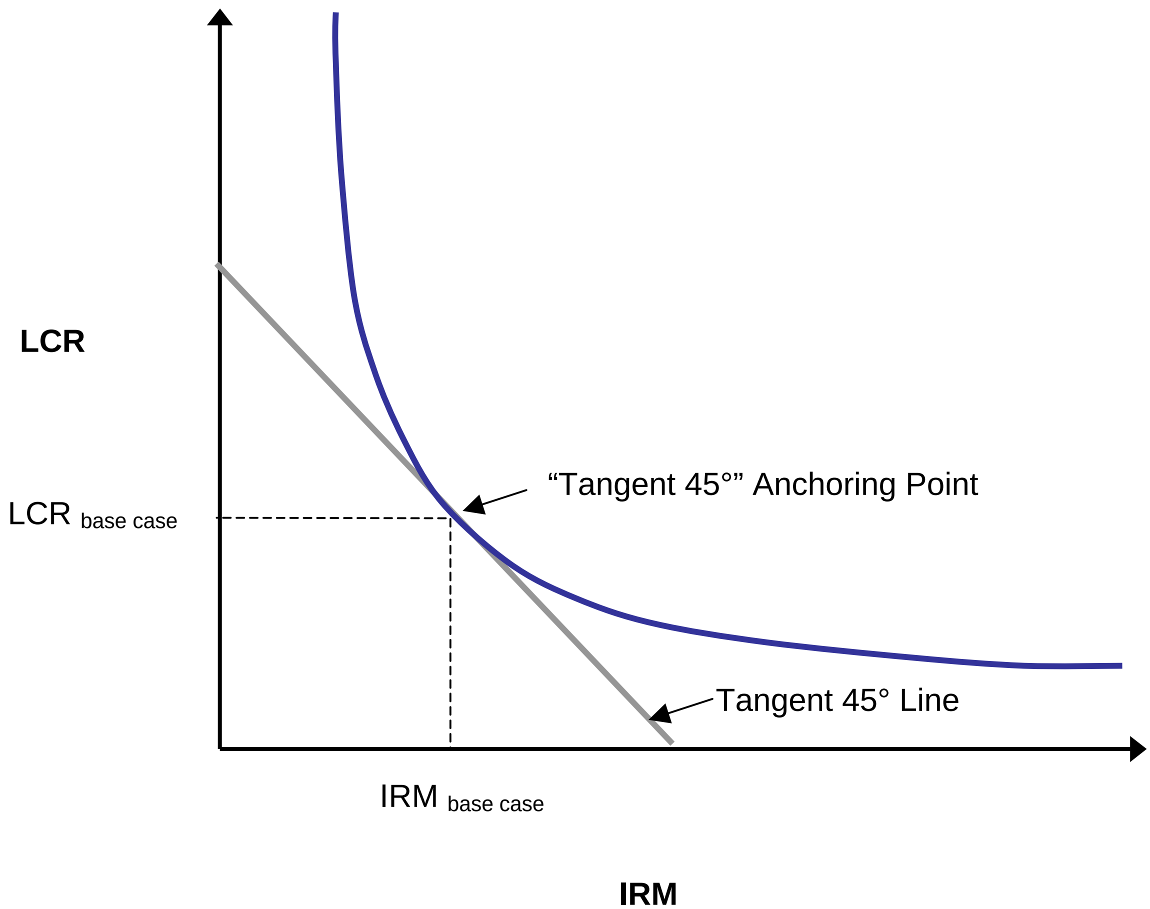
APPENDIX E: Resource Situations of PJM/MAAC and New England





** Year when new resources are needed.

APPENDIX F: Illustrative Example Tangent 45° Anchoring



APPENDIX G: Cost-Benefit Analysis Details

a. Calculation of Levelization Factors

For each resource option the total capital investment is converted to a levelized annual charge in nominal dollars. The capital structure of the investment is assumed to be 50% debt and 50% common equity with straight-line depreciation for both revenue requirement and tax computations. The costs of debt and equity capital were assumed to be 7.5% and 12.5% respectively for a 20-year investment based on the 2004 report by Levitan and Associates.[50]

The economic lives of the resource options were assumed to be as follows:

- Central station generation 30 years
- Transmission 30 years
- Distributed generation 20 years
- Demand side measures
  - Commercial HVAC 15 years
  - Motors 20 years
  - Commercial Lighting 15 years
  - Residential Lighting 10 years
  - Residential HVAC 20 years

Using the costs and structure of capital given in the Levitan report as a basis annual nominal levelization rates were calculated for investment economic lives of 10, 15, 20, and 30 years. Figure G1 shows the resultant levelization factors.

[50] Levitan and Associates, "*Independent Study to Establish Parameters of the ICAP Demand Curves for the New York Independent System Operator*", August 16, 2004

Figure G1. Capital Structure Assumptions and Levelization Rates

	%	Cost*	Return	After-Tax
Debt	50.00%	7.50%	3.75%	2.06%
Equity	50.00%	12.50%	6.25%	6.25%
	100.00%		**10.00%**	**8.31%**
Depreciation:	Straight line			
Federal Income Tax:	35%			
Gross Receipts Tax:	10%			
Property Taxes:	Included in Fixed O&M Costs			

*** Cost of debt for a 15 year economic life is assumed to be 7%**

Nominal Levelization Rates

Economic Life (yrs)	Nominal Rate
10	19.69%
15	16.19%
20	14.86%
30	13.90%

Source: Levitan Report

b. Energy Revenues

Benefits derived from energy sales (or savings) help offset the investment cost of installing generation, transmission and demand side resources. Energy benefits can be quantified as the annual energy revenue received (or monetary savings realized) net of fuel cost and variable operating and maintenance expenses:

Energy Benefit [$/MW-yr] = (Energy Revenues or Savings – Fuel Cost) [$/MW-yr]
– Variable O&M [$/MWh] x (Capacity Factor) x (#hrs/yr)

The benefit is an annual value *per MW of installed capacity*, levelized over the life of the resource. The term in parenthesis on the right hand side of the equation is simply the gross margin from energy sales or savings and can be expressed as the difference between the market heat rate and the plant operating heat rate multiplied by the fuel cost:

Gross Margin [$/MW-yr] = (Energy Revenues or Savings – Fuel Cost)
= (Market H.R. – Plant H.R.) [MMBtu/MWh] x Fuel Price [$/MMBtu]
x (Capacity Factor) x (#hrs/yr) x F

The energy benefit is then:

Energy Benefit [$/MW-yr] = { (Market H.R. – Plant H.R.) [MMBtu/MWh]
x Fuel Price [$/MMBtu] – Variable O&M [$/MWh] }
x (Capacity Factor) x (#hrs/yr) x F

where,

Capacity Factor = Total energy generated, transferred or saved by the resource divided by its maximum capability.

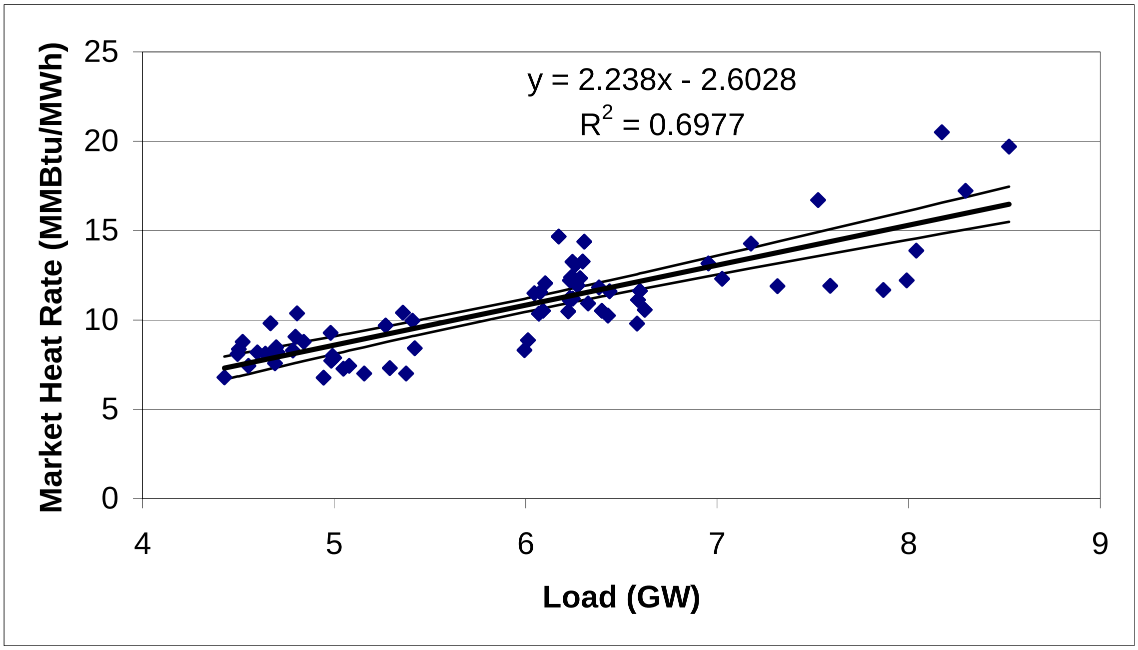
(#hrs/yr) = Total number of hours in one year, typically 8,760.

F = Levelization factor (see Section "e" below)

To determine a representative market heat rate for the study, energy price and load data were examined for years 2002, 2003, and 2004. Figure G2 shows a plot of Zone J market heat rate vs. load for this three-year period. Data points represent monthly average market heat rates for peak and off-peak periods plotted against monthly average load for those same periods. Hence there are 24 (12 monthly on-peak and 12 monthly off-peak)[51] data points for each year, and 72 points for the 3-year period.

Figure G2. Market Heat Rate vs. Load for Years 2002, 2003, and 2004

Data points show monthly peak and off-peak averages. Upper and lower 95% confidence limits are also shown.



Using the correlation on Figure G2, it is estimated that the annual average market heat rate over the long run in zone J to be about 10,000 Btu/kWh. It is understood that generation investments tend to be lumpy and there will be years

[51] On-peak hours are non-holiday weekdays from 7AM to 11PM. All other times are considered off-peak.

when market heat rate is higher when reserve margins are low or lower when reserve margins are high.

The annual average market heat rate is suitable for base loaded resources such as a CCGT plant. However, depending on their marginal cost of operation, there are resources that run mainly during certain seasons and/or peak periods, and see a different market heat rate during operation. Therefore, similar market heat rate data analyses were conducted for specific periods that characterize the annual load shape. These include summer super-peak, summer capability period peak, and annual off-peak. Figure G3 shows each of these periods, the resources that are assumed to run predominantly during those periods, and the average market heat rates calculated for each period.

Figure G3. Market Heat Rates for Various Periods during the Year

Period	Description	Resources Affected	Market Heat Rate (Btu/kWh)
Annual Average	Average of all hours throughout the year	CCGT, AC and DC Transmission, DG units with CHP, Commercial Lighting, and Motors	10,000
Annual Off-peak	Weekends, Holidays, and non-holiday weekdays 11 PM to 7 AM	Residential Lighting	8,315
Summer super-peak	June through August non-holiday weekdays between 11 AM and 6 PM	Non-CHP DG units	16,484
Summer capability period peak	April through October non-holiday weekdays between 7 AM and 11 PM	SCGT, Solar PV, Commercial and Residential HVAC	12,982

Plant heat rates used for the study are shown on Figure 15 under Section 5.2.

A range of likely capacity factors for each resource was determined based on past experience. Energy revenues were calculated for the range of likely capacity factors and then a representative single capacity factor was chosen for each resource in reporting the final results.

Figure G4 lists the capacity factors used in the study.

Figure G4. Capacity Factors of Generation and Transmission Resources

Resource	Capacity Factor Range	Representative Value Used
Simple Cycle Gas Turbine (SCGT)	10% - 20%	15%
Combined Cycle Gas Turbine (CCGT)	40% - 70%	50%
Out-of-City SCGT with radial tie	10% - 20%	15%
Out-of-City CCGT with radial tie	40% - 70%	50%
AC line with phase angle regulator	60% - 90%	75%
HVDC line	60% - 90%	75%
Microturbine	3% - 10%	5%
Microturbine CHP	50% - 80%	60%
IC Engine (natural gas fired)	3% - 10%	5%
IC Engine CHP (natural gas fired)	50% - 80%	60%
Molten Carbonate Fuel Cell	3% - 10%	5%
Molten Carbonate Fuel Cell CHP	50% - 80%	60%
Photovoltaic*	-	17.5%

* Photovoltaic (solar cell) capacity factor determined based on annual sunlight intensity for New York City

c. Treatment of Demand Side Energy Efficiency (EE) Measures

Demand side measures are unique in how their costs are calculated and how they contribute to peak load reduction. Unlike a generation or transmission asset, the capital cost of a demand side measure is the incremental cost of the measure per unit of peak coincident load reduction:

$$\text{DSM EE Capital Cost} = \frac{\text{(Cost of Efficient Measure)} - \text{(Cost of Conventional Equipment)}}{\text{Peak Coincident Load Reduction Provided by the Measure}}$$

Not all of the load reduction from efficiency measures occurs during peak hours. For example, it is estimated that about 10% of residential lighting is on during peak periods. Therefore, in order to achieve 1 MW of coincident peak load reduction through a residential lighting program, enough lighting must be installed to yield 10 MW of non-coincident load reduction. All of the energy benefit from the 10 MW can then be credited towards the calculation of the net cost of capacity. In contrast, the same ratio for commercial HVAC is 90%, or 1.11 MW of non-coincident peak load reduction required to ensure 1 MW of coincident peak load reduction. These coincident load factors need to be included in the calculation of the capacity factor for DSM, as follows:

DSM capacity factor based on coincident peak load reduction =
DSM capacity factor based on non-coincident peak load reduction / (coincident load factor)

Figure G5 illustrates the calculation of capacity factors for the DSM measures considered in the study.

Figure G5. Capacity Factors for DSM Energy Efficiency Measures

Measure	Primary Operating Pattern	A = Capacity Factor Based on Non-Coincident Peak Load Reduction[52]	B = Coincident Load Factor[53]	Capacity Factor Based on Coincident Peak Load Reduction = A/B
Commercial HVAC	Summer capability period peak	0.17	0.911	0.187
Commercial Lighting	Annual Base loaded	0.30	0.578	0.519
Motors		0.46	0.78	0.590
Residential HVAC	Summer capability period peak	0.12	0.84	0.143
Residential Lighting	Annual off-peak	0.11	0.103	1.068

Note that, as with residential lighting, these capacity factors based on coincident peak load reduction may be greater than one. As stated earlier this is because the capital costs of these measures reflect a greater gross load reduction than the peak coincident value.

d. Accounting for Uncertainties

Since the cost figures pertain to generic (non site-specific) resources, uncertainties naturally exist. The uncertainty factors to be applied to the cost values for each resource type have been determined based on historically observed cost ranges and were vetted through the SRAS Collaborative.

Fuel price uncertainty was handled by doing a sensitivity analysis. The calculation was repeated with two fuel prices; one that reflects the current forecast and one that reflects a lower value based on expectations of fuel price. Factors influencing the expectation of lower gas prices over the long run include development of new LNG resources and dissipation of current market anxieties over rising oil prices.

The uncertainty of input parameters was translated into uncertainty in the results by using scientific error propagation formulas:

Addition and subtraction

$$U(x+y) = U(x - y) = [U(x)^2 + U(y)^2]^{1/2}$$

[52] Based on Con Edison's past Enlightened Energy Program
[53] NYSERDA DSM Programs Database, June 2005 internal release.

Multiplication and division

$U(xy) = xy[(U(x)/x)^2 + (U(y)/y)^2]^{1/2}$
$U(x/y) = x/y[(U(x)/x)^2 + (U(y)/y)^2]^{1/2}$

Where U(x) denotes uncertainty of the input variable x.

e. Levelization of Annual Energy Benefits

Since the capital costs were levelized through an annual carrying charge, the energy benefits calculated to offset the capacity cost must also be similarly levelized. This is done by selecting a representative fuel price from the forecast and escalating it up or down at the rate of inflation (assumed constant at 3%) to get a fuel price stream over the years of interest. This fuel price stream can then be levelized using the rate of inflation to yield the same value for each year.

Effectively, this procedure results in a levelizing factor to be applied to the representative fuel price. The levelization factor used for each resource varies with the economic life of the resource, as illustrated on Figure G6 below.

Figure G6. Levelization Factor for Calculating Energy Benefits

Economic Life	F = Levelization Factor
10	1.11
15	1.19
20	1.24
30	1.34

Assumption: Energy benefits vary only by inflation

APPENDIX H: Additional GE-MARS Simulation Results

In this appendix, the GE-MARS simulation results using the Con Edison internal database are presented.

Figure H1 shows the reliability benefit of adding 250 MW relative to adding 500 MW of the same resource option. Noting that in 2010 the NYCA need is about 500 MW in order to meet the one day in ten years LOLE reliability criterion, most of the reliability benefit of a resource option of 500 MW comes in the second 250 MW block. This is especially true for DSM energy efficiency measures, and because of this, there may be more reliability benefit by using DSM energy efficiency to supplement the reliability need rather than fully rely on DSM energy efficiency to meet the need.

Figure H1. Reliability Benefit of 250 MW versus 500 MW to NYCA in 2010

	Expected Time Interval Between Loss of Load Events = 1/LOLE (in years)		Ratio of Reliability Benefit of 250 MW to 500 MW
Resource Option	**With 250 MW Resource Option**	**With 500 MW Resource Option**	
CCGT	2.78	6.49	43%
Customer owned generation (DG)	2.64	6.94	38%
DSM energy efficiency	3.14	14.05	22%

Figure H2 shows the reduction in the LOEE or unserved energy in NYCA as a result of adding 500 MW of the resource options considered.

Figure H2. Reliability Benefit of 500 MW Resource Options in 2010 in Terms of LOEE Improvement

Resource Option	Reduction in NYCA LOEE or Unserved Energy (MWh / year)
SCGT	724
CCGT	724
Out-of-City SCGT with radial tie	724
Out-of-City CCGT with radial tie	724
Transmission with firm capacity (PJM)*	724
Transmission (free-flowing) from PJM	0.1
Transmission with firm capacity (Lower Hudson Valley)	0.1
Transmission (free-flowing) from Lower Hudson Valley	0.1
Customer owned generation (DG)*	724
DSM energy efficiency	964

It should be noted that the GE-MARS model outputs LOEE values of the state of the system immediately prior to the emergency operating procedures (EOPs) steps in the simulations. EOPs include voltage reductions, emergency demand response programs, and SCRs, all of which are steps taken before a loss of load event occurs. As a result, measuring reliability benefit using LOEE reductions would not fully capture the reliability benefit of resource options that may be categorized as an EOP, such as DGs, which are typically modeled as SCRs.

On Figure H2, the LOEE results from the MARS simulations using the Con Edison internal database for the two cases with an asterisk (*) are suspect. However, based on the LOLE reliability results from GE using the NYISO proprietary database as shown on Figure 20, the results should be about the same as those of the SCGT or CCGT and therefore are estimated to be such here. Not surprising, the LOEE results as shown on Figure H2 are consistent with the LOLE results, that is, the resource option with greater LOLE benefit also has greater LOEE benefit.

APPENDIX I: List of Acronyms

The following is a list of frequently used acronyms that are found throughout this report:

AC	Alternating Current
C/B Ratio	Cost to Benefit Ratio
CAGR	Compound Annual Growth Rate
CCGT	Combined Cycle Gas Turbine
CERA	Cambridge Energy Research Associates
CHP	Combined Heat and Power
The City	New York City
Con Edison/the Company	Consolidated Edison Company of New York, Inc.
CONE	Cost of New Entry
CPB	New York State Consumer Protection Board
CRPP	Comprehensive Reliability Planning Process
DC	Direct Current
DG	Distributed Generation
DPS	New York State Department of Public Service
DSM	Demand Side Management
ECM	Electronically Commutated Motor
EDRPs	Emergency Demand Response Programs
EE	Energy Efficiency
EFORd	Equivalent Forced Outage Rate
EOPs	Emergency Operating Procedures
ERRP	East River Repowering Project
FEIS	Final Environmental Impact Statement
FERC	Federal Energy Regulatory Commission
GE	General Electric Company
GT	Gas Turbine
H.R.	Heat Rate
HIR	Halogen Infrared
HRSG	Heat Recovery Steam Generator
HVAC	Heating, Ventilating, and Air Conditioning
HVDC	High Voltage Direct Current
IC	Internal Combustion
ICAP	Installed Capacity
ICS	Installed Capacity Subcommittee (of the NYSRC)
IPPNY	Independent Power Producers of New York
IRM	Installed Reserve Margin
LBNL	Ernest Orlando Lawrence Berkeley National Laboratory
LCR	Locational Capacity Requirement
LED	Light Emitting Diode
LHV	Lower Hudson Valley (Zones G, H, and I)
LIPA	Long Island Power Authority
LNG	Liquefied Natural Gas
LOEE	Loss of Expected Un-served Energy
LOLE	Loss of Load Expectation
LSE	Load Serving Entity
MARS	Multi Area Reliability Simulation
MC/MCFC	Molten Carbonate/Molten Carbonate Fuel Cell
NOx	Nitrogen Oxides
NYCA	New York Control Area
NYCEDC	New York City Economic Development Corporation
NYECC	New York Energy Consumers Council
NYISO	New York Independent System Operator
NYPA	New York Power Authority
NYSDEC	New York State Department of Environmental Conservation
NYSERDA	New York State Energy Research and Development Authority
NYSRC	New York State Reliability Council
OC	Operating Committee (of the NYISO)

ODP	Open Drip-Proof
PJM	PJM Interconnection
PPA	Power Purchase Agreement
PSC	New York State Public Service Commission
PULP	Public Utility Law Project
PV	Photovoltaic
RFP	Request for Proposal
RNA	Reliability Needs Assessment
SCGT	Simple Cycle Gas Turbine
SCRs	Special Case Resources
SENY	Southeast New York
SO_2	Sulfur Dioxide
SRAS	System Reliability Assurance Study
SRIS	System Reliability Impact Study
The State	New York State
ST	Steam Turbine
TO	Transmission Owner
UCAP	Unforced Capacity
UDR	Unforced Capacity Deliverability Rights
UPNY	Upstate New York
UWUA	Utilities Workers Union of America